CRITICAL ISSUES IN ELECTRIC POWER PLANNING IN THE 1990s

VOLUME II

K. Morgan MacRae

STUDY NO. 33
NOVEMBER 1989

Canadian
Energy
Research
Institute

CRITICAL ISSUES IN ELECTRIC POWER PLANNING IN THE 1990s

VOLUME II

K. MORGAN MACRAE

Canadian Energy Research Institute
3512 -33rd Street N.W.
Calgary, Alberta
T2L 2A6
(403) 282-1231

December 1989

91-01736/

CRITICAL ISSUES IN ELECTRIC POWER PLANNING IN THE 1990s

VOLUME II

K. MORGAN MACRAE

Critical Issues in Electric Power Planning
in the 1990s Volume II

Copyright © Canadian Energy Research Institute, 1989
Sections of this study may be reproduced in magazines and newspapers with acknowledgment to the Canadian Energy Research Institute. The views expressed in this study are those of the author and do not necessarily represent those of Energy, Mines and Resources Canada, the Alberta Energy Resources Conservation Board, the Canadian Energy Research Institute, its directors, officers, staff or funding organizations.

Author: Morgan MacRae
Editor: Anthony Reinsch
Artist: Robert M. Sharp

CANADIAN ENERGY RESEARCH INSTITUTE
3512 - 33RD STREET N.W.
CALGARY, ALBERTA
CANADA T2L 2A6

TELEPHONE: (403) 282-1231
FAX. NO.: (403) 284-4181

December 1989

The Canadian Energy Research Institute (CERI) is a cooperative research organization established by government and industry parties in 1975. The Institute's principal role is to undertake objective, independent studies and thereby assist business and government in making energy and energy-related decisions and policy choices. Related important objectives are the ongoing government/industry review of energy issues and policies, the development of expertise in the analysis of energy matters and the general enhancement of public understanding of Canadian energy affairs.

The sponsors of the Institute are Energy, Mines and Resources Canada, the Alberta Department of Energy, the Private Energy Research Association (composed of some eighty corporate members from the energy production, transportation, marketing, distributing and consuming industries in Canada and abroad and from the financial community), the University of Calgary, the Ontario Ministry of Energy, the Alberta Department of Transportation and Utilities, the Energy Resources Conservation Board, and the British Columbia Ministry of Energy, Mines and Petroleum Resources. In addition, the Institute is supported by grants from International Associate Sponsors (mainly energy departments and agencies of foreign governments and research organizations) which benefit from CERI research pertaining to oil, natural gas, coal and electricity economics.

CERI's research program is determined by a Board of Directors named by the sponsoring organizations. Project advisory committees comprised of experts from government and industry are established to assist Institute staff and to review preliminary drafts of CERI reports. Responsibility for the content of studies rests with the authors and the officers of the Institute. All studies are placed in the public domain.

TABLE OF CONTENTS

LIST OF FIGURES xiii
LIST OF TABLES xvii
PREFACE xxi
APPENDIX A A HISTORICAL OVERVIEW OF THE CANADIAN ELECTRICITY INDUSTRY 1
A.1 Introduction 3
A.2 The Early Beginnings: 1880-1910 . . . 4
A.3 The Growth of Electricity Supply 9
A.4 The Changing Structure of Electricity Demand 18
A.5 Public Ownership and Regulation . . . 28
A.6 Trade in Electricity 39
A.7 Conclusion 44
APPENDIX B PROVINCIAL VIGNETTES 57
B.1 British Columbia 59
B.2 Alberta 77
B.3 Saskatchewan 89
B.4 Manitoba 101
B.5 Ontario 115
B.6 Quebec 131
B.7 New Brunswick 143
B.8 Nova Scotia 155
B.9 Prince Edward Island 163
B.10 Newfoundland 173
B.11 The Yukon and Northwest Territories 183
APPENDIX C FUTURE REQUIRED CAPACITY ADDITIONS 195
APPENDIX D UNITED STATES EXPERIENCE 209
D.1 Structure of the Industry 211
D.2 Regulatory History 212
D.3 Legislation and Regulatory Jurisdiction 216
D.4 The Public Utility Regulatory Policies Act and its Implications 221
D.5 Changing Directions in Regulation 225
D.6 Further Regulatory Alternatives 237

APPENDIX E CANADIAN ELECTRICAL GENERATING PLANNING MODEL (ELGEM) 259

E.1 Description 261
E.2 Model Capabilities 262
E.3 Model Inputs 262
E.4 Model Variables 263
E.5 Scenario Results 263

APPENDIX F GLOSSARY 281

DETAILED BIBLIOGRAPHY 301

[The following Table of Contents outlines
the main study published
under separate cover]

VOLUME I

TABLE OF CONTENTS

LIST OF FIGURES xiii

LIST OF TABLES xvii

PREFACE xix

CHAPTER 1 INTRODUCTION 1

- 1.1 Focus 2
- 1.2 Modelling 4
- 1.3 Outline 4

CHAPTER 2 FUTURE CAPACITY ADDITIONS 7

- 2.1 Introduction 7
  - 2.1.1 Analytical Approach 8
  - 2.1.2 Limitations of Forecasts 9
- 2.2 An Overview of Electricity Demand 10
  - 2.2.1 The Composition of Electricity Demand 11
    - 2.2.1.1 Industry 11
    - 2.2.1.2 Transportation 16
    - 2.2.1.3 Residential 16
    - 2.2.1.4 Commercial 17
  - 2.2.2 The Uncertainty of Electricity Demand 17
- 2.3 Capacity Additions Motivated by Internal Demand 19
  - 2.3.1 The Existing Supply/Demand Balance 20
  - 2.3.2 Base Demand Growth Scenario 21
  - 2.3.3 Expected Capacity Additions 21

2.4 Sensitivity to Higher Demand Growth 27
2.5 Sensitivity to Power Exports 31

  2.5.1 Review of Export Opportunities 32

    2.5.1.1 British Columbia 32
    2.5.1.2 Manitoba 34
    2.5.1.3 Quebec 34
    2.5.1.4 New Brunswick 36
    2.5.1.5 Nova Scotia 36
    2.5.1.6 Newfoundland 37

  2.5.2 Effect on Capacity Additions 37

2.6 Interpretation and Analysis 38

  2.6.1 Fuel Type 38
  2.6.2 Decision Dates 42
  2.6.3 Historical Comparison 45

2.7 Conclusions 47

CHAPTER 3 DEMAND MANAGEMENT 55

3.1 Introduction 55
3.2 DSM Defined 57
3.3 DSM Implementation 64
3.4 DSM Benefits and Costs 66

  3.4.1 Benefits 67
  3.4.2 Costs 68

3.5 Demand-Side Management in the United States 70
3.6 Demand-Side Management in Canada 73

  3.6.1 British Columbia 74
  3.6.2 Ontario 74
  3.6.3 DSM Prescriptions 79

3.7 Conclusions 80

CHAPTER 4 NON-UTILITY GENERATION 87

4.1 Economic Rationale for Electricity Regulation 87
4.2 Contribution of Non-Utility Generation 94

4.2.1 Existing Contribution 95
4.2.2 Power Purchase Policies 96
4.2.3 Potential for NUG 96

4.3 Impacts of Market Structure on NUG 101

4.3.1 Market Access 102
4.3.2 Price Determination 103

4.4 Incentives and Barriers to Non-Utility Generation 105

4.4.1 Technical Incentives and Barriers 105
4.4.2 Economic Incentives and Barriers 106
4.4.3 Fiscal Incentives and Barriers 109
4.4.4 Other Issues 110

4.5 Non-Utility Generation in the U.S. 111

4.5.1 PURPA Legislation 112
4.5.2 Lessons from the U.S. 116

4.6 Conclusions 117

CHAPTER 5 ELECTRICITY TRADE 125

5.1 Introduction 125

5.1.1 Types of Trade 126

5.2 Historical Overview of Electricity Trade 126

5.2.1 International 126
5.2.2 Interprovincial 138

5.3 The Prospects for Trade 140

5.3.1 U.S. Overview 140
5.3.2 The U.S. Regional Implications 143

5.3.2.1 New England 143
5.3.2.2 New York 144
5.3.2.3 Midwest 144
5.3.2.4 West 145
5.3.2.5 Synopsis-- U.S. Prospects 146

5.3.3 Interprovincial Trade 147

5.4 Constraints to Trade 150

5.4.1 Technical Considerations 150
5.4.2 Capacity 152
5.4.3 Reliability 153
5.4.4 Health Effects of High-Voltage Transmission 154
5.4.5 The U.S. Debate Over Canadian Power Imports 156
5.4.6 The Wheeling Issue 159

5.4.6.1 Arguments For and Against Wheeling 161
5.4.6.2 Transmission Access to Wheel Electricity Exports ... 162
5.4.6.3 Transmission Access Through a Purpose-built Line 164
5.4.6.4 Synopsis 165

5.5 Modelling Interprovincial and International Electricity Flows 165

5.5.1 Trade Scenarios 166

5.6 Conclusions 171

CHAPTER 6 ELECTRICITY AND THE ENVIRONMENT 179

6.1 Introduction 179
6.2 Atmospheric Emissions 183

6.2.1 Acid Rain 183
6.2.2 Ground Level Ozone 185
6.2.3 The Greenhouse Effect and Global Warming 188

6.3 Recent Initiatives to Limit Atmospheric Emissions 192

6.3.1 The SO_2 Protocol 192
6.3.2 The NO_x Protocol 193
6.3.3 CO_2 Initiatives 193
6.3.4 Canada/U.S. Bilateral Agreements on Acid Rain 196
6.3.5 The Significance of Target Reductions 197

6.4 Pressures on the Canadian Electrical Sector to Reduce Acid Gas Emissions 197

6.4.1 Trends in Canadian Acid Gas Emissions 197
6.4.2 Provincial Distribution of Acid Gas Emissions 206

6.4.2.1 Sulphur Dioxide 206
6.4.2.2 Nitrogen Oxides 211

6.5 Utility Emission Targets 211

6.5.1 Industry Response 213

6.5.1.1 Acid Gas Abatement . . 213
6.5.1.2 Coal Cleaning 217
6.5.1.3 Coal Switching 217
6.5.1.4 Conventional Control Technologies 218
6.5.1.5 Advanced Clean Coal Technologies 219
6.5.1.6 Coal Displacement . . . 222

6.6 Implications for Fossil-Fired Generation 222

6.6.1 Ontario 223
6.6.2 Nova Scotia and New Brunswick 225

6.7 The CO_2 Question 226

6.7.1 The Dimensions of the Problem 226
6.7.2 Canadian CO_2 Projections 230
6.7.3 Fossil Fuel Displacement 230

6.7.3.1 Hydro Power 234
6.7.3.2 Nuclear Power 234
6.7.3.3 Improved Efficiency . . . 235

6.7.4 Marching Out of Step 236

CHAPTER 7 KEY FINDINGS AND CONCLUSIONS 247

7.1 Introduction 247

7.1.1 The Uncertainty of Electricity Demand 248

7.2 Key Findings 249

7.2.1 Capacity Additions 249
7.2.2 Demand Management 251
7.2.3 Non-Utility Generation 252

7.2.4 Electricity Trade 254
7.2.5 Environment 256

7.3 Conclusions 259
7.4 Recommendations 261

7.4.1 Electricity Trade 262
7.4.2 Non-Utility Generation 262
7.4.3 Demand-Side Management 262
7.4.4 Environment 263

GLOSSARY 267

BIBLIOGRAPHY 285

LIST OF FIGURES

A.1 Electricity Generation by Fuel Type, Canada, 1919-1965 6

A.2 Electricity Generation by Fuel Type, Canada, 1965-1987 13

A.3 Electric Utility Annual Investment Canada, 1965-1987 17

A.4 Electricity Demand Growth by Decade, Canada, 1920-1987 21

A.5 Electricity Consumption by Sector, Canada, 1937-1987 22

A.6 Real Electricity Price Changes, Canada, 1972-1987 25

A.7 Final Energy Consumption by Fuel, Canada, 1970-1987 26

A.8 Per Capita Electricity Consumption Canada, 1988 29

A.9 Generation by Type of Ownership Canada, 1919-1965 34

A.10 Canada Electricity Exports and Imports, 1930-1987 42

A.11 Canadian Electricity Exports, 1970-1987 43

British Columbia

B.1 British Columbia Electricity Supply, 1987 63

B.2 British Columbia Electricity Demand, 1987 64

B.3 British Columbia Electricity Prices, 1987 66

Alberta

B.1 Alberta Electricity Supply, 1987 80

B.2 Alberta Electricity Demand, 1987 82

B.3 Alberta Electricity Prices, 1987 83

Saskatchewan

B.1 Saskatchewan Electricity Supply, 1987 92

B.2 Saskatchewan Electricity Demand, 1987 93

B.3 Saskatchewan Electricity Prices, 1987 94

Manitoba

B.1 Manitoba Electricity Supply, 1987 103

B.2 Manitoba Electricity Demand, 1987 105

B.3 Manitoba Electricity Prices, 1987 106

Ontario

B.1 Ontario Electricity Supply, 1987 118

B.2 Ontario Electricity Demand, 1987 119

B.3 Ontario Electricity Prices, 1987 121

Quebec

B.1 Quebec Electricity Supply, 1987 134

B.2 Quebec Electricity Demand, 1987 135

B.3 Electricity Prices in Quebec, 1987 137

New Brunswick

B.1 New Brunswick Electricity Supply, 1987 145

B.2 New Brunswick Electricity Demand, 1987 147

B.3 New Brunswick Electricity Prices, 1987 149

Nova Scotia

B.1 Nova Scotia Electricity Supply, 1987 157

B.2 Electricity Prices in Nova Scotia, 1987 158

B.3 Nova Scotia Electricity Demand, 1987 160

Prince Edward Island

B.1 Prince Edward Island Electricity Demand, 1987 166

B.2 Sources of Electricity Generation in Prince Edward Island (1976-1987) 167

B.3 Electricity Prices in Prince Edward Island - 1987 168

Newfoundland

B.1 Newfoundland Electricity Supply, 1987 176

B.2 Newfoundland Electricity Demand, 1987 178

B.3 Newfoundland Electricity Prices, 1987 180

Yukon and Northwest Territories

B.1 Yukon Territory Electricity Supply, 1987 185

B.2 Yukon Electricity Demand, 1987 187

B.3 Northwest Territories Electricity Supply, 1987 189

B.4 Northwest Territory Electricity Demand, 1987 191

B.5 Electricity Prices in the Yukon and Northwest Territories - 1987 192

LIST OF TABLES

A.1 Electricity Consumption by Sector, Canada, 1987 27

A.2 Private Electricity Generation in Canada, 1987 36

A.3 Important Dates in the Development of Electricity Supply 45

A.4 Important Dates in the Development of Public Power 48

British Columbia

B.1 Integrated B.C. System, Capacity and Reserve, 1987 62

B.2 B.C. Electricity Trade, 1987 67

B.3 Interconnection Capacity, British Columbia, 1987 69

B.4 Integrated B.C. System, Major Development Projects 71

Alberta

B.1 Alberta Interconnected System, Capacity and Reserve, 1987 81

Saskatchewan

B.1 Saskatchewan Power System, Capacity and Reserve, 1987 91

B.2 Saskatchewan Electricity Trade, 1987 96

B.3 Interconnection Capacity, Saskatchewan, 1987 97

Manitoba

B.1 Integrated Manitoba System, Capacity and Reserve, 1987 104

B.2 Manitoba Electricity Trade, 1987 108

B.3 Interconnection Capacity, Manitoba, 1987 109

B.4 Manitoba Hydro, Major Development Projects 111

Ontario

B.1 Ontario Hydro System, Capacity and Reserve, 1987 117

B.2 Ontario Electricity Trade, 1987 122

B.3 Interconnection Capacity, Ontario, 1987 123

B.4 Ontario Hydro, Major Development Projects 125

Quebec

B.1 Electrical Generating Capacity and Reserve, Quebec, 1987 133

B.2 Quebec Electricity Trade: Selected Data, 1983-1987 138

New Brunswick

B.1 NB Power System, Capacity and Reserve, 1987 144

B.2 New Brunswick Electricity Trade, 1987 150

B.3 Interconnection Capacity, New Brunswick, 1987 151

Nova Scotia

B.1 Electrical Generating Capacity and Reserve, Nova Scotia, 1987 156

Prince Edward Island

B.1 Electrical Generating Capacity and Reserve, Prince Edward Island, 1987 165

Newfoundland

B.1 Integrated Newfoundland System, Capacity and Reserve, 1987 175

B.2 Newfoundland and Labrador Hydro, Major Development Projects 177

Yukon and Northwest Territories

B.1 Electrical Generating Capacity and Reserve in the Yukon and Northwest Territories, 1987 186

B.2 Growth in Electricity Consumption and Peak Demand, Yukon and the Northwest Territories - 1975-2005, Average Annual Growth Rates 188

C.1 Canada Total, Future Required Capacity Additions 197

C.2 British Columbia Total, Future Required Capacity Additions 198

C.3 Alberta Total, Future Required Capacity Additions 199

C.4 Saskatchewan Total, Future Required Capacity Additions 200

C.5 Manitoba Total, Future Required Capacity Additions 201

C.6 Ontario Total, Future Required Capacity Additions 202

C.7 Quebec Total, Future Required Capacity Additions 203

C.8 New Brunswick Total, Future Required Capacity Additions 204

C.9 Nova Scotia Total, Future Required Capacity Additions 205

C.10 Prince Edward Island Total, Future Required Capacity Additions 206

C.11 Newfoundland Total, Future Required Capacity Additions 207

C.12 Yukon and Northwest Territories Total, Future Required Capacity Additions 208

Preface

This project was a joint undertaking of the Canadian Energy Research Institute (CERI) and the Policy Studies Group of the Energy Policy Sector of Energy, Mines and Resources Canada. The project was conceived to address the myriad of important and, at times, controversial issues contributing to a period of significant change and uncertainty in the Canadian electricity industry.

CERI would like to thank the Policy Studies Group for their participation and acknowledge the following contributions. Sonia L'Heureux, Baxter MacDonald and James Stanford researched and wrote the provincial electricity vignettes contained in Volume II of this report. James Stanford was responsible for Chapter 2 on future capacity additions in the Canadian electricity industry and authored the historical overview of the industry contained in Volume II. Sonia L'Heureux co-authored Chapter 4, dealing with non-utility generation; Baxter MacDonald co-authored Chapter 6, dealing with the environmental constraints that will strongly influence utility planning decisions in the 1990s. Paul-André Rochon and Nik Marty of the Policy Studies Group assisted CERI in the design and management of the study.

Two other organizations made significant contributions to CERI's research. I would like to acknowledge the valuable work undertaken by Dr. Adrienne Kwaczek, formerly of the Alberta Energy Resources Conservation Board (ERCB) on regulatory developments in the United States (Volume II). Thanks is also due to the Alberta Research Council and, in particular, the contributions of Drs. Don Quon and Sam Wong who developed a model for CERI to assess future electricity supply, demand and trade patterns. Also acknowledged is the assistance of Mr. B. Emmett, formerly with Energy, Mines and Resources Canada and Dr. P. Prince (ERCB) for their assistance in arranging staff support from these organizations for this project.

The many individuals who served on the Advisory Committee to this study also contributed in a major way and their support and advice is gratefully acknowledged. As with all CERI research projects, the Advisory Committee offered their insight and constructive criticism on the draft report. The Advisory Committee was composed of experts from 15 organizations representing industry, government, and academia in Canada, the United States and abroad.

Special thanks are due to a number of the Institute's staff: Janice Morrison and Beverly Kovacs, who processed the interim drafts and final manuscript; Megan Murphy, who created the graphics; and Zaytoon Janjua and Wendy Faid of the I.N. McKinnon Memorial Library, who gathered source materials from across the continent. Finally, my thanks to my colleague, Tony Reinsch, for his careful review and insightful comments.

This study brings together of historical and current information on Canada's electric power system. An historical overview of Canadian electric power and the provincial vignettes contained in Volume II provide the context for Volume I where we discuss important issues facing Canadian electric power planning. This report specifically analyzes the current and prospective importance of a number of key issues, any one of which would be worthy of a detailed, book-length inquiry. To discuss all of these topics together required that the analysis be succinct and, at times, somewhat abbreviated.

The Institute hopes that you find this research study of interest, and that it addresses issues of specific importance. CERI is undertaking further analyses on Canadian electric power and to ensure the most pertinent research, we encourage your continued support, views and commentary.

APPENDIX A

A HISTORICAL OVERVIEW OF THE CANADIAN ELECTRICITY INDUSTRY

Appendix A

A HISTORICAL OVERVIEW OF THE CANADIAN ELECTRICITY INDUSTRY

A.1 Introduction

The present structure and level of development of the electricity industry in Canada is the product of a 100-year history. From the first isolated experimental generators in a few Canadian cities in the 1880s to the massive hydroelectric and nuclear-powered megaprojects of the 1980s, Canada's electricity companies have evolved and adapted in the face of major changes to every aspect of their business. Demand trends, supply technologies, the political and regulatory environment, and international and interprovincial trade patterns have all had a profound effect on the shape of the electricity industry and its role in the economy as a whole. To acquire a comprehensive understanding of the issues and constraints presently facing this industry, therefore, it is useful to review the history of electricity production and consumption in Canada.

This historical overview begins with a condensed description of the early beginnings of the electricity industry, from the first electricity generators installed for local lighting purposes in the 1880s to the pioneering central generating systems of the early twentieth century. The second section provides an overview of the subsequent development of electricity supply, from the first small hydro plants through to the construction of northern megaprojects, a growing reliance on thermal capacity, and the introduction of nuclear power. The third section describes the quantitative and qualitative changes that have been experienced in electricity demand, and how these changes have provided an additional impetus for the expansion of generating capacity and distribution networks. The fourth section examines the changing structure of the electricity industry, discussing the reasons for the rise of public ownership and regulation in Canada's electricity industry. The fifth section summarizes the history of electricity trade in Canada, both between individual provinces and with the United States. Finally, this historical overview concludes with a recapitulation of those historical influences that have been most important in shaping today's electricity system in Canada.

Due primarily to the fact that the electricity industry in Canada falls under provincial jurisdiction, each province and territory has had its own unique experience with the development of electricity supply and demand. Because of space limitations, however, as well as our desire to identify common themes that cross provincial boundaries, this historical overview will not deal in detail with the history of electricity in each province. Instead, the evolution of this industry will be described in broad terms for Canada as a whole, with detailed reference to particular provinces where necessary.

A.2 The Early Beginnings: 1880-1910

Canada's early telegraph system was the first significant application of the technology of electricity in this country. Starting in the late 1840s, telegraph lines were constructed to link communities, provinces, and eventually continents. Similarly, long-distance telephone systems were also established in the 1870s, starting with Alexander Graham Bell's pioneering long-distance connection between Brantford and Paris, Ontario, in 1876.[1] These systems were powered by electric batteries, however, and it was not until the 1880s that electrical generation for the purposes of light, heat, and power began to be developed in Canada.

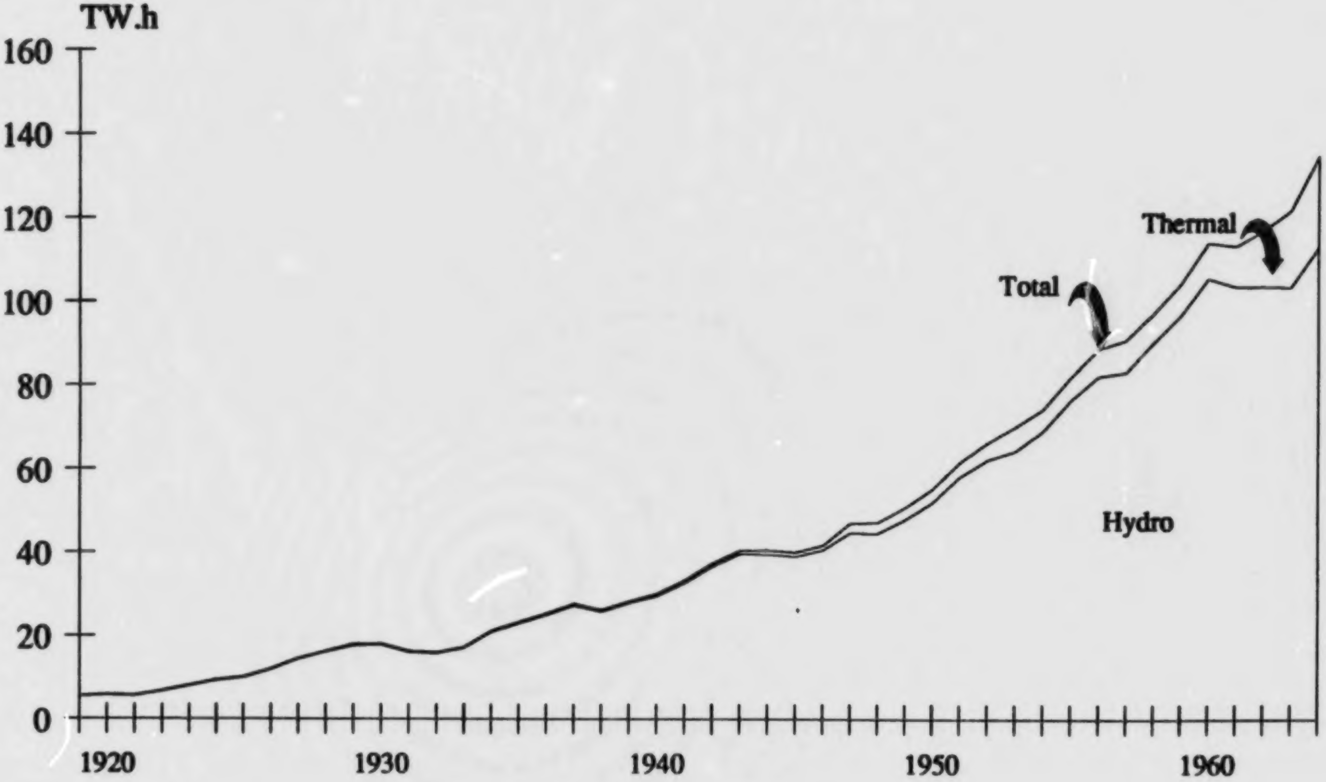
Demonstrations of the marvel of electric light had attracted considerable attention in several of Canada's major cities, and by 1885 many had installed primitive, isolated generating stations to power factory or street lighting systems and, occasionally, electric urban transportation services. These early generating stations were generally coal-fired, very small (seldom more than a few hundred kilowatts in capacity), and located very close to the point of demand, since the technology of electricity transmission was very undeveloped. Early progress was also made at this time in harnessing Canada's abundant hydroelectric power, which was distributed more evenly between provinces than were fossil fuels. One of North America's first hydraulic generators was placed in service in 1882 at Chaudiere Falls on the Ottawa River,[2] and other small hydro developments were subsequently constructed in those cities which were located adjacent to suitable rivers and streams. Most major cities, however--most notably Toronto and Montreal--did not possess sufficient hydroelectric resources within their city limits, and had to rely on thermal generation until advances in long-distance transmission were made several years later.

The early generating plants were typically owned by small, ambitious promoters who were able to raise the relatively modest capital required to purchase or construct a small generator. Most of the revenue accruing to these first electricity companies would often come from a street-lighting contract signed with the local civic government, or some other single customer to whom the bulk of the company's generating capacity was dedicated. It was not until the early twentieth century that the central generating station--one which served a variety of customers from a single generating unit--became well-established. The electricity business was a risky, speculative and cut-throat industry at this time. The numerous small producing firms were subject to the vagaries of an unproven technology and an unstable market. Prices for electricity, which was considered a luxury during this early period of development, were very high, ranging between ten and twenty-five cents per kilowatt-hour--equivalent to as much as $3.00 per kilowatt-hour in real 1988 dollar terms.

By the turn of the century, a combination of technological advancement and a changing pattern of ownership in the electricity industry resulted in the gradual elimination of this highly decentralized and volatile industrial structure. On the supply side, new construction techniques made it possible to build hydroelectric generating facilities whose capacity was measured in megawatts instead of kilowatts. Simultaneously, breakthroughs in the technology of transmission allowed for the power from these early hydraulic 'megaprojects' to be delivered to demand centres that were many miles away. The new transmission technology brought hydroelectric resources within reach of virtually all of the major population centres in Canada (with the possible exceptions of Prince Edward Island and certain regions of the Prairie provinces), so that from the turn of the century until the 1960s, hydroelectricity provided virtually all of Canada's generating requirements (see Figure A.1).

This new chapter in the development of electricity supply in Canada is illustrated particularly well by two path-breaking projects, which together provided for a major portion of the energy needs of the country's industrializing heartland. The first of these projects was the development of the hydroelectric potential of the St. Maurice River near Trois-Rivieres, Quebec.[3] This region had already been the site of an important breakthrough in electricity supply in Canada: in 1897, the North Shore Power Company (formed by a local entrepreneur and backed by a Sherbrooke banker) successfully carried out the first long-distance transmission of electricity in the British Commonwealth, a

Figure A.1
Electricity Generation by Fuel Type
Canada, 1919 - 1965



SOURCE: Historical Statistics of Canada,
Series Q85-91.

distance of 18 miles from a generating station on the Batiscan River to the town of Trois-Rivieres. The subsequent development of the St. Maurice, however, would dwarf this feat in its significance for the future of the electricity industry. A second firm from Trois-Rivieres, the Shawinigan Electric Light and Power Company, paid $60,000 to the provincial government in 1897 for the right to develop the 145-foot Shawinigan Falls, located 25 miles north of the St. Lawrence River. By 1903, the first generating station at this site was completed (producing some 40 MW of power), and electricity was being transmitted 90 miles to Montreal on a 50-kV high-voltage line--the longest and highest voltage transmission system in the world. Montreal was thus provided with abundant and relatively cheap electricity to service its growing industry and population. This power was distributed to a growing and diverse number of customers through a centralized distribution system controlled by the Montreal Light, Heat and Power Company, which bought the bulk power from the Shawinigan firm.

The second of these early megaprojects was the development of the hydraulic potential of the Canadian side of Niagara Falls. For 10 years, Canadians had looked enviously at impressive electricity developments on the American side of the massive falls. By 1896, three major power plants there were producing a total of more than 100 MW of power, and had sparked a mini-industrial revolution in the Niagara Falls, New York area--with the establishment of several factories to utilize the abundant and cheap power for new electrochemical industrial processes, such as the production of aluminum, carbides, abrasives, chemicals and other products.

The first hydroelectric plant on the Canadian side of the falls was a small 2-MW station built in 1893 to supply electricity to the International Railway Company's tramline in the Welland area. The bulk of the potential of the Canadian falls was left untouched, however, until three large plants were completed within 5 years at the turn of the century. The first of these plants, located at Rankine, Ontario, was opened in 1901 and produced 90 MW of power for export to the Buffalo, New York region.[4] It was built by the Canadian Niagara Power Co. Ltd., a subsidiary of the Niagara Falls Power Co. of New York. The terms of the company's water lease (purchased from the provincial government for $25,000 per year) stipulated that 50 percent of the plant's output had to be reserved for Canadian buyers, but at that time there were no willing takers.[5] Within 2 years, construction had started on two more large stations: a 25-MW plant built by the Ontario Power Co. (another subsidiary of a U.S. firm), and a 125-MW plant built by the Electrical Development Company (controlled by Toronto utility magnates William Mackenzie, Frederic Nicholls and Henry Mill Pellatt).[6] By 1910, high-voltage transmission lines were installed to deliver a portion of their power to Toronto and other cities in southwestern Ontario. As late as 1915, these three companies alone still accounted for over 70 percent of the electricity generated in Ontario.[7]

These two developments were by no means the only major hydro projects completed at this time to serve distant urban demand centres. In 1906, Winnipeg was connected to the first generating units at the 22-MW Pinawa power plant, 70 miles away. Three years later, the Calgary Power Co. started construction of a 14-MW station at Seebe, 50 miles west of the city.[8] Similar projects were undertaken in New Brunswick, Newfoundland, and British Columbia. The Shawinigan and Niagara developments were the largest, however, and they best dramatize the effect of new generation and transmission technology on the structure of the electricity industry. No longer was electricity supply a business that could be approached by independent local entrepreneurs with a few thousand dollars in capital and a willingness to take risks. These new developments required capital investments of millions of dollars; they required a carefully planned distribution system to reach service areas covering many hundreds of square miles; and they required enough staying power on the part of the investors to survive a construction and market development period that could last several years.

It is not surprising, then, that this new phase in electricity supply was accompanied by a period of rapid concentration in the electricity industry, as the more successful small utilities combined themselves into larger and larger trusts. It was also accompanied by a large infusion of foreign investment, especially from the U.S., which helped to satisfy some of the huge capital requirements of the early projects. We have already seen that two of the three large generating stations on the Canadian Niagara were owned by U.S. investors; the third was financed by the Toronto Electric Light Company, a large electricity and street railway monopoly, which had evolved through a series of mergers and acquisitions. The main investors in the Shawinigan Water and Power Company were a group of Boston financiers, led by J.E. Aldred;[9] the amount of U.S. capital invested in the firm exceeded $10 million by 1905. Crucial to the firm's success was its collusive relationship with Montreal Light, Heat and Power, which had itself been incorporated in 1901, a product of the consolidation of private electricity and gas utilities in Montreal. A similar pattern of ownership was typical of the other utilities in Canada; indeed, there was even a certain degree of cross-ownership between the big utilities, such as William Mackenzie's controlling interests in both the Electrical Development Company of Toronto and the Winnipeg Electric Street Railway Co. (builder of the Pinawa generating station).[10]

So by 1910, three decades after the first commercial applications of electric power in Canada, two predominant trends had established themselves. First, the bulk of the country's rapidly growing electricity needs were met by major hydroelectric developments, often located long distances from the urban centres that they primarily served. This is a characteristic that is still reflected in the electricity industries of several Canadian provinces. Second, the supply of this electricity fell under the control of increasingly concentrated private utilities, which often depended on the participation of U.S. investors. This pattern of ownership in the electricity industry, unlike its continued reliance on hydroelectricity, would change dramatically in subsequent decades, thanks to the rise of the public power movement.

A.3 The Growth of Electricity Supply

As illustrated in Figure A.1, hydroelectricity provided the vast majority of Canadian electricity supply, from the advent of centralized power stations described above until the 1960s.[11] The early hydro developments, at sites such as the St. Maurice and Niagara Rivers, provided sufficient electrical supply for the major industrial and population centres of Canada until World War I, when the development of larger facilities was necessitated by the pressing industrial and energy demands of the war effort.

Subsequent hydroelectric plants, commissioned during the 1920s, were larger and more efficient. In 1921, for example, the Ontario Hydroelectric Power Commission (later Ontario Hydro) commissioned its first major generating station, the Queenston-Chippewa facility on the Niagara River, downstream from Niagara Falls. It boasted the largest power capacity of any of the Niagara developments, and when the final generating units were installed in 1930, its 392-MW capacity made it the largest hydro plant in the world.[12] Simultaneously, between 1920 and 1930 the Shawinigan Water and Power Company added almost 400 MW of generating capacity to its hydroelectric facilities, primarily through additional generating units at Shawinigan Falls and other stations on the St. Maurice and Mattawin Rivers.[13] The company's 550 MW of capacity in 1930 made it by far the largest electricity supplier in Quebec. In 1922 the Winnipeg Electric Street Railway Co. connected the first two generating units on its Great Falls hydro development, which boasted a total capacity of 132 MW when completed in 1928. This facility introduced a new propeller turbine technology that greatly enhanced the efficiency of hydroelectric generation, and utilized an operating head that was the highest in the world at the time.[14]

Investment in hydroelectric generating facilities by private industrial power users also contributed substantially to the growth of supply capacity during the inter-war period. This represented a continuation of a trend established prior to World War I, when several pulp and paper companies decided to build their own hydroelectric stations on rivers in northern Ontario and Quebec. Much larger generating stations were constructed after the war on Quebec's Saguenay River by the Duke-Price company and by the Aluminum Company of America, to power their pulp and paper and aluminum production facilities, respectively. Similarly, the Gatineau River in western Quebec was developed by the Gatineau Power Company, a subsidiary of the International Paper Company, for pulp and paper mills in the region.[15] A 60-MW facility was built on the St. John River at Grand Falls, New Brunswick in 1928 to supply power for pulp and paper mills located over 100 miles away; the transmission of electricity from this facility took place over a 132-kV high-voltage line, one of the highest voltage transmission facilities in the world at the time.[16] Similarly, the Deer Lake generating station on Newfoundland's Humber River was opened in 1925 to power the Newfoundland Pulp and Paper Company's operations at Corner Brook; by 1929, the plant had a capacity of 128 MW and supplied additional power to mining companies in the region.[17] Some of these industrial generating stations also provided excess power for domestic requirements in nearby population centres, but this function was generally secondary to their use as dedicated power sources for new industrial and manufacturing facilities.

By 1932, Canada possessed total generating capacity of about 6000 MW, mostly in hydroelectric facilities. This represented a fourfold increase from the capacity that had existed at the end of World War I. Total capital investment in electric utilities at this time approached $1.4 billion, making the electricity industry the second largest in Canada (after railways) in terms of capital stock invested.[18] It was already clear that the electricity industry would play a central role in Canadian economic development, thanks both to its sheer size and to the importance of electricity supply for the stimulation of other industries.

With the economic recession of the 1930s, however, the fast pace of growth in Canadian electricity supply slowed dramatically. Capacity continued to grow during the first few years of the decade, despite the recession, as projects that had been commissioned during the late 1920s were completed. Many utilities were seriously hurt during the Depression by a sharp slowing of electricity demand which accompanied the fall-off in economic activity. This left many utilities with considerable excess capacity following the great construction boom of the previous decade. By 1935, the pace of capacity expansion had slowed to a virtual halt. The average annual increase in capacity in Canada between 1935 and the outbreak of World War II was barely 2 percent, compared to a vigorous rate of growth that averaged almost 8 percent per year before the Depression.[19]

The advent of World War II and the sustained post-war expansion inspired a renewed boom in electric utility construction activity. To a large extent, this post-war growth in electricity supply was qualitatively similar to the developments of the 1920s. More and larger hydroelectric generating stations were built, accompanied by longer and higher-voltage transmission lines to deliver their power to the large urban markets.

Typical of this period was the Beauharnois project on the St. Lawrence River near Montreal, the first major construction project undertaken by the newly-formed provincial utility, Hydro-Quebec. While located relatively close to the city of Montreal, where most of the facility's output would be consumed, this project was unique in terms of its scale of construction. The excavation required to finish the station was 15 percent greater than that required to build the Panama Canal; when its second phase was installed in 1953, Beauharnois became the first generating facility in Canada to exceed 1000-MW capacity. It was completed in 1961 with a total capacity of 1600 MW, making it the largest hydraulic generating facility in Canada until the Churchill Falls development was completed in 1974.[20]

Hydro-Quebec launched another trail-breaking megaproject in 1959, with the start of construction on its Manicougan-Outardes generating complex in the north-east of the province. Located in near-wilderness hundreds of miles from the major load centres, this complex would foreshadow future hydro developments in northern Manitoba, B.C., Labrador, and Quebec. The first power from the 5500-MW project was delivered in 1965 over a 735-kV transmission line to Quebec City and Montreal, at the time the highest voltage commercial power transmission facility in the world.

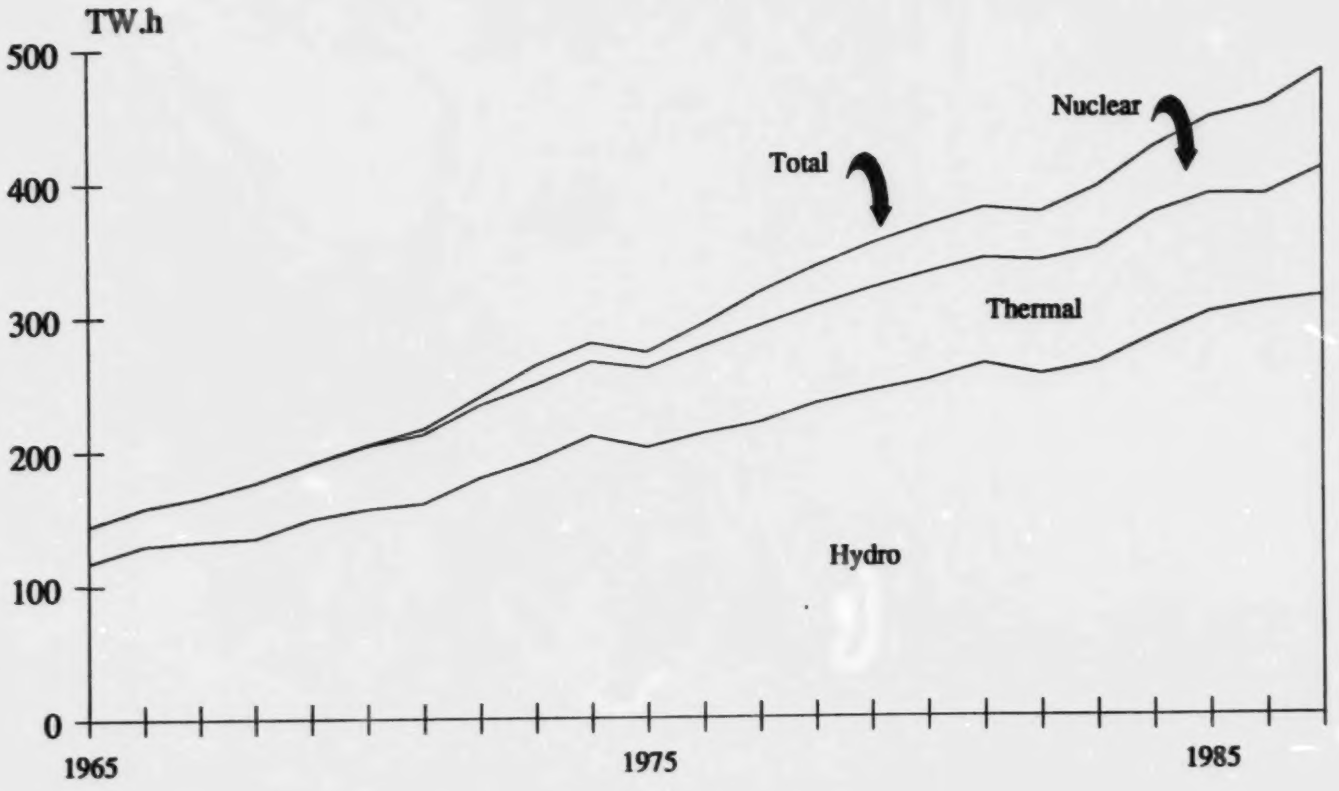
While Quebec's hydroelectric system made the most ambitious use of distant rivers for purposes of electrical generation during the 1950s and 1960s, other provinces were following a similar pattern of development as the search for feasible hydroelectric sites extended farther and farther from the southern population centres. Ontario Hydro set its sights upon the energy potential of the St. Lawrence River, with the construction of the Robert H. Saunders plant starting in 1954; Ontario's share of the facility, which was built jointly with the New York State Power Authority, is 960 MW. The construction of the Sir Adam Beck #2 Station at Niagara Falls--the last major development on the Canadian side of the falls--added another 1288 MW to Ontario's hydroelectric capacity in the late 1950s.

Major hydraulic developments in other provinces during this period included the 236-MW Kelsey station on Manitoba's Nelson River, which was completed in 1960 to power Inco's operations at Thompson, and was the first major hydroelectric development in northern Manitoba. Industrial power demand was also the main motive behind the 1962 opening of the 225-MW Twin Falls plant in Labrador, which was built to supply the British Newfoundland Company's iron operations, and which laid the groundwork for the subsequent development of Churchill Falls. Meanwhile, on the island of Newfoundland, the Newfoundland and Labrador Power Commission started construction in 1964 on the initial 450-MW phase of the giant Bay d'Espoir hydro development (later expanded to over 600 MW). Even provinces comparatively poor in hydroelectric resources completed ambitious projects to harness whatever hydraulic potential existed within reach of the major cities, such as Saskatchewan's 280-MW Squaw Rapids project, completed in 1963.

As the post-war economic boom continued, however, it became increasingly clear that hydroelectric power alone would not be sufficient to satisfy all of Canada's burgeoning electricity requirements. From the mid-1960s onward, Canadian electricity supply became increasingly diversified between hydroelectric facilities, fossil-fuel plants, and eventually nuclear-powered generating stations (see Figure A.2). In 1950, fully 95 percent of Canada's electricity was generated by hydroelectric facilities; by 1965 this share had fallen to 80 percent, and has continued its decline since then to its present share of about 65 percent.[21] Initially, the only alternatives to

Figure A.2

Electricity Generation by Fuel Type
Canada, 1965 - 1987



SOURCE: Statistics Canada, Electric Power in Canada.

increasingly scarce hydroelectric capacity were conventional thermal facilities fired by coal, oil or natural gas. Fuel selection depended on the availability of indigenous feedstock, comparative fuel prices and security of supply.

Alberta's utilities opted for coal-fired plants, usually located adjacent to utility-owned coal fields in order to reduce transportation costs. These were supplemented by a significant concentration of natural gas-fired capacity in Edmonton, Medicine Hat, and other urban centres. Saskatchewan's thermal capacity was also based on largely indigenous coal reserves, as was Nova Scotia's. Oil-fired facilities were built at St. John's, Newfoundland starting in 1956, and near St. John, New Brunswick starting in 1959. Ontario Hydro's thermal capacity was shared between oil and coal-fired facilities.

These thermal plants were generally seen as somewhat less desirable than hydraulic facilities. Consequently, they were usually constructed only in those provinces which lacked additional hydraulic capacity, or which expected near-term demand growth too rapid to allow for the longer lead times associated with hydroelectric developments. In a few cases, however, the thermal option was preferred even where hydroelectric potential existed, either to take advantage of local fossil fuels (this was especially true in Alberta), or to reduce required capital expenditures by the utility (since the capital cost of thermal plants is lower than for hydroelectric capacity, while their operating expenses are higher).[22]

Thermal capacity developments in that era were not seriously hampered by two considerations that proved to be of overwhelming importance in subsequent decades: environmental protection and instability of world oil prices. Utilities shouldered certain expenses to moderate the most immediate environmental consequences of thermal facilities--usually focused on such problems as thermal pollution in adjacent lakes and rivers or localized air pollution problems. But today's concern with the long-term effects of air pollution, acid deposition, and global warming was not really considered when the decisions were taken to construct thermal capacity in the 1950s and 1960s. Similarly, since few, if any, observers expected the sharp oil price shocks of the 1970s, oil-fired plants were constructed in Ontario and the Maritimes without considering the impact of a dramatic change in feedstock prices on their viability. Oil at the time was an inexpensive, abundant, versatile and clean fuel that was preferable to coal in the minds of many utility planners. Needless to say, no major new oil-fired generating stations have been commissioned since OPEC launched its first round of world oil price increases in 1973-1974.[23]

A third option was introduced into the Canadian electricity repertoire with the development of commercial nuclear power in the 1960s. Starting in 1954, technicians with Atomic Energy Canada Ltd. (AECL), Ontario Hydro, and other utilities began research at the Chalk River Nuclear Laboratories near Ottawa, in order to parlay Canada's existing nuclear expertise (gained through its contribution to the Allied military program in World War II and to peaceful medical and physics applications since 1945) into an economically feasible electricity technology. The eventual result was the unique CANDU technology, which differs from other nuclear generating technologies in that the reactor is cooled with heavy water and can be refuelled during operation, thus allowing for a much higher average utilization rate.

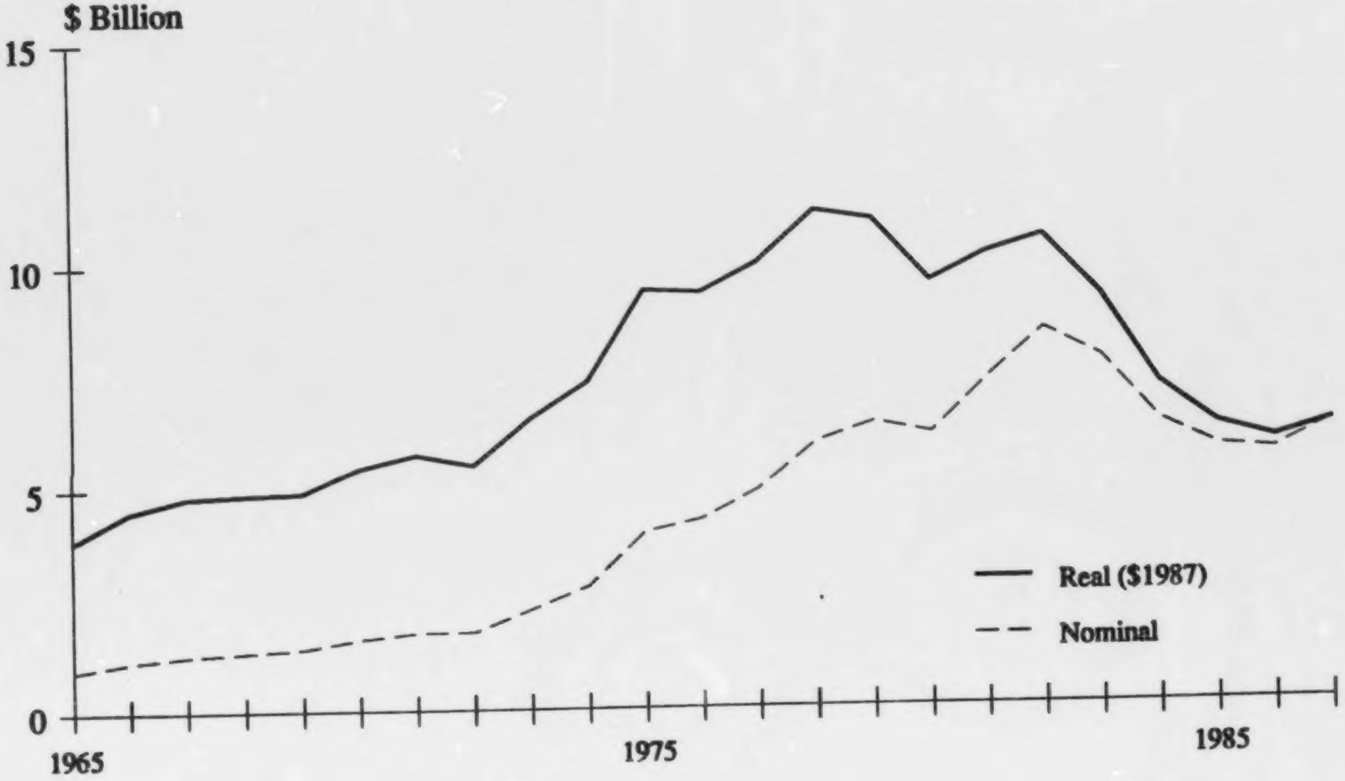
A 25-MW nuclear demonstration generator began operation in 1962 at Rolphton, Ontario, and went on to contribute power to Ontario Hydro's grid for 25 years before being decommissioned in 1987.[24] Before this demonstration plant had even been completed, design work was initiated for the first full-scale commercial nuclear power plant, a 200-MW facility at Douglas Point, Ontario, which entered service late in 1966. Since then, Ontario Hydro has taken the leading role in developing nuclear power in Canada. The first two units of the first nuclear megaproject, the Pickering complex, went into service in 1971. Five years later, the first 825-MW generating unit of the Bruce complex was commissioned; its total completed capacity of 6600 MW made it the largest single generating station of any kind in Canada. Three nuclear power plants were also built outside of Ontario. Two of these reactors were built in Quebec: an experimental 230-MW light-water reactor, commissioned in 1971, and the 685-MW Gentilly 2 station. The third is the 680-MW CANDU reactor at Point Lepreau, New Brunswick, which was brought on line in 1983.

It is interesting, in retrospect, to review the enthusiasm with which Canadian utility planners initially pursued the nuclear power option. In its early years, it was seen as the source of limitless, inexpensive energy. Many utility planners in the 1960s believed that even hydroelectric developments would be rendered obsolete by the efficient new nuclear technology. This early enthusiasm was considerably dampened during the 1970s, however, by public concerns with the environmental risks associated with nuclear power stations and the problems of radioactive waste disposal. Safety and environmental measures have subsequently added to the capital and operating costs of nuclear facilities, although it is argued that the nuclear option has still proven to be less expensive than equivalent fossil-fuelled capacity.

Ontario and New Brunswick are the only provinces which have chosen to develop a significant reliance on nuclear power. Other regions in Canada continued to rely on hydraulic and conventional fossil-fuelled thermal facilities to meet growing electricity demand through the 1970s and 1980s. In the hydroelectric sphere, the trend towards larger, more remote projects was continued by utilities in Newfoundland, Quebec, Manitoba and B.C. Each new project, it seemed, marked another landmark in construction methods and/or long-distance transmission technology. The 5400-MW Churchill Falls development in Labrador, which started producing electricity in 1971, has been called an "eighth wonder of the world";[25] it is still the largest single hydroelectric station in Canada. The scale of the $15 billion James Bay development in Quebec defied imagination and played a major role in shaping the self-image of Quebec society; the first units of a total of over 10 000-MW capacity in the project's three giant generating stations began producing power in 1979. Manitoba's massive Nelson River, which drains a watershed that includes over 50 percent of the Prairies, and which enjoys a natural reservoir in the form of Lake Winnipeg, was developed jointly by the provincial and federal governments following a 1966 Agreement. To date, capacity in excess of 2500 MW has been completed in four stations on the river, with another 1300 MW to be added when the Limestone station is completed in 1990. Manitoba has also significantly advanced the technology of long-distance transmission, with its pioneering +/-450-kV direct current line to Winnipeg from the Nelson River stations (first energized in 1971). British Columbia, too, has broken new ground with its hydroelectric megaprojects, including the spectacular 800-foot-high Mica Dam (built in the 1970s as part of B.C. Hydro's obligations under the 1961 Columbia River Treaty) and the Peace River development in the north-east of the province.

The sum of these gigantic hydroelectric developments--together with Ontario Hydro's nuclear megaprojects and the ongoing construction of conventional thermal facilities in Alberta, Saskatchewan, Nova Scotia and elsewhere--resulted in a massive boom in investment spending by Canadian utilities that lasted from the early 1970s until the beginning of the 1980s (see Figure A.3). At its peak in 1978, this investment expenditure reached over $11 billion (in real 1987 terms), accounting for 11 percent of all investment in the Canadian economy and 58 percent of all Canadian energy

Figure A.3
Electric Utility Annual Investment
Canada, 1965 - 1987



SOURCE: EMR Canada, Electric Power in Canada.

investment.[26] In retrospect, this construction blitz turned out to be a substantial over-investment in new capacity by Canadian utilities. The second world oil price shock of 1979-80, and the subsequent recession of 1982, contributed to a sharp decline in electricity demand growth in Canada. By 1982, virtually all Canadian utilities found themselves with significant quantities of excess capacity, forcing them to postpone further capacity additions, and in many cases leading them to adopt a more aggressive marketing strategy in certain export and domestic markets (see sections on demand and trade below).

Sustained economic growth in Canada over the second half of the 1980s has contributed to a resurgence of electricity demand growth, and there are now indications that utilities may be preparing themselves for another cycle of major capacity expansion. Real investment by utilities increased by some 6 percent in 1987, and is likely to pick up further momentum in coming years as major new construction projects are initiated in Ontario, Quebec and other provinces.

A.4 The Changing Structure of Electricity Demand

The consumption of electricity in Canada has undergone as many dramatic changes over the past 100 years as has electricity supply. Indeed, the relationship between the demand and supply of electricity has been a complex and two-way interaction ever since the first primitive generating facilities were put in place. The early electricity entrepreneurs identified needs in the economy that could be better served by the emerging new technology of electric power. Their investments in generating capacity were a response to those demands, but their success in providing increasingly inexpensive power from larger and more efficient facilities in turn stimulated the creation of new sources of electricity demand.

In certain circumstances, electricity supply was a response to an existing demand, while at other times demand grew almost unexpectedly in reaction to prevailing supply conditions. An early example of this complex interrelation was the first hydroelectric developments at Niagara Falls. The initial generating stations on both the Canadian and the U.S. side of the falls were built with an eye on the street-lighting and commercial market in Buffalo, New York, some twenty miles distant. But the cement had hardly dried on the first hydroelectric installations when a rapid influx of modern electricity-intensive manufacturing industries--spawned by the promise of cheap and abundant power--made Niagara Falls, New York the ultimate destination of most of the plants' output.[27] This recursive pattern, in which supply is developed in response to an identified demand but in turn stimulates a new and greater source of demand, has been repeated several times during the development of Canada's electricity industry.

As mentioned above, the first major uses of electricity in Canada were street-lighting and urban transportation in the larger cities. But these sources of electricity demand were quickly overwhelmed in importance by rapid increases in the use of electric heat and power by industries. To some extent, this industrial demand was based on a conversion to electric energy by established manufacturing industries for purposes of lighting and motive power. Small-scale manufacturers in southwestern Ontario, for example, were the major interest group behind the Ontario government's establishment of Ontario Hydro in 1906, because they believed that the application of electricity to their existing industrial processes would make their businesses more efficient and competitive.[28]

More important to the growth of electricity demand, however, was the rapid development of specialized, electricity-intensive industries, such as pulp and paper or aluminum reduction--industries which owed their very existence to the potential abundance of Canadian hydroelectricity. These operations were established in Quebec, Newfoundland, Ontario, British Columbia and a few other parts of the country starting around the turn of the century. Occasionally they relied on electricity supply provided by a separate utility; more often, in these early days, they built their own generating facilities in order to guarantee a dedicated, reliable and inexpensive power supply.

With the exception of Ontario, where electricity demand was more diversified, these new industries quickly laid claim to the lion's share of electricity supply in most Canadian provinces. In Quebec in 1931, for example, the pulp and paper industry consumed almost 40 percent of all firm electric power utilized in the province; the growing aluminum industry took another 14 percent.[29] In Ontario at the same time, general manufacturing was the largest single user of electricity, accounting for 27 percent of consumption, almost twice as much as pulp and paper's 15 percent share of supply.[30] As late as 1948, the pulp and paper industry in Newfoundland consumed an astounding 93 percent of all electricity produced on the island.[31] Where these and other manufacturing industries did not establish themselves, the demand for electricity was almost non-existent; in 1932, for example, Quebec's electricity consumption was more than 50 times greater than the combined electricity consumption of Alberta and Saskatchewan.[32]

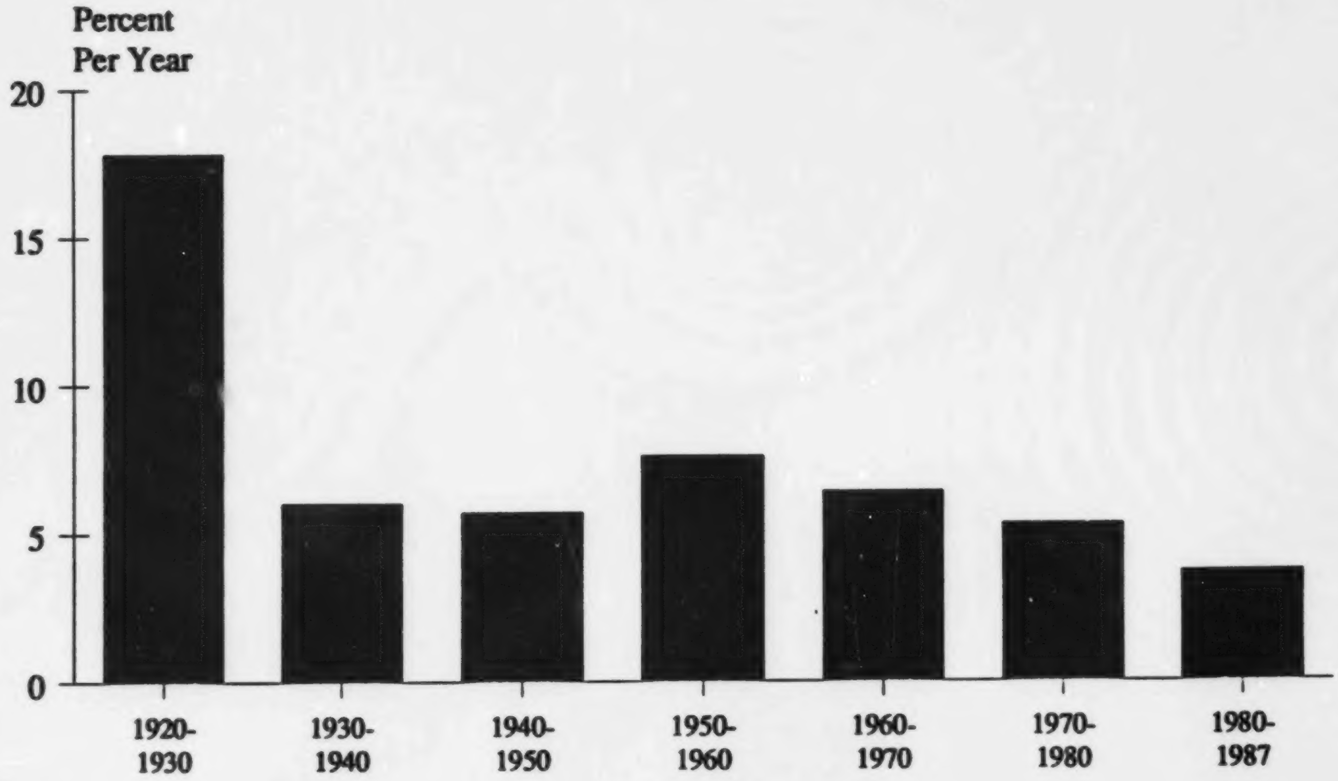
By the early 1930s, then, the conversion of Canadian industry to electric power was essentially complete. The sharp increases in industrial electricity consumption were the most important factor behind the large annual increases in electricity demand that were typical of the booming 1920s (see Figure A.4). The industrial sector became responsible for a large majority of Canadian electricity demand, and this would remain the case until the 1960s. But while it was this strong and growing core of industrial demand that provided most of the impetus for the early expansion of electrical generating capacity, the utilities were already searching for other sources of electricity demand that could supplement and diversify their load beyond the industrial base.

Major marketing efforts were undertaken, even during the relatively bleak years of the Depression, to promote the use of electricity in homes, offices and the retail sector. Utilities would aggressively market electric home appliances, often offering free repairs or other incentives as a means of increasing residential demand. In its earlier days, electricity was seen as an expensive luxury by most Canadians, but the new marketing strategies of the utilities now portrayed electricity as being necessary for day-to-day life. The "Better Light, Better Sight" campaign, aimed at convincing mothers that electric lights would benefit their children's health and education, was an example of this attempt to crack the domestic market.[33] Some inroads were gained into the residential and commercial markets during the 1920s and 1930s, but it was not until the post-war economic boom that rising real incomes first put electric power within the reach of virtually all Canadians. Most provinces carried out subsidized rural electrification programs following the war, and these also stimulated electricity consumption amongst Canada's still sizable rural population. Since World War II, the growth of residential and commercial electricity sales has been considerably faster than demand growth in the industrial sector, with the result that the industrial share of total consumption has declined steadily (see Figure A.5).

The pricing policies of Canadian utilities have influenced the sectoral composition of electricity demand, as well as the overall rate of demand growth. While consumption in the residential and commercial sectors was relatively insignificant prior to World War II in terms of volume, these customers made a disproportionate contribution to the

Figure A.4

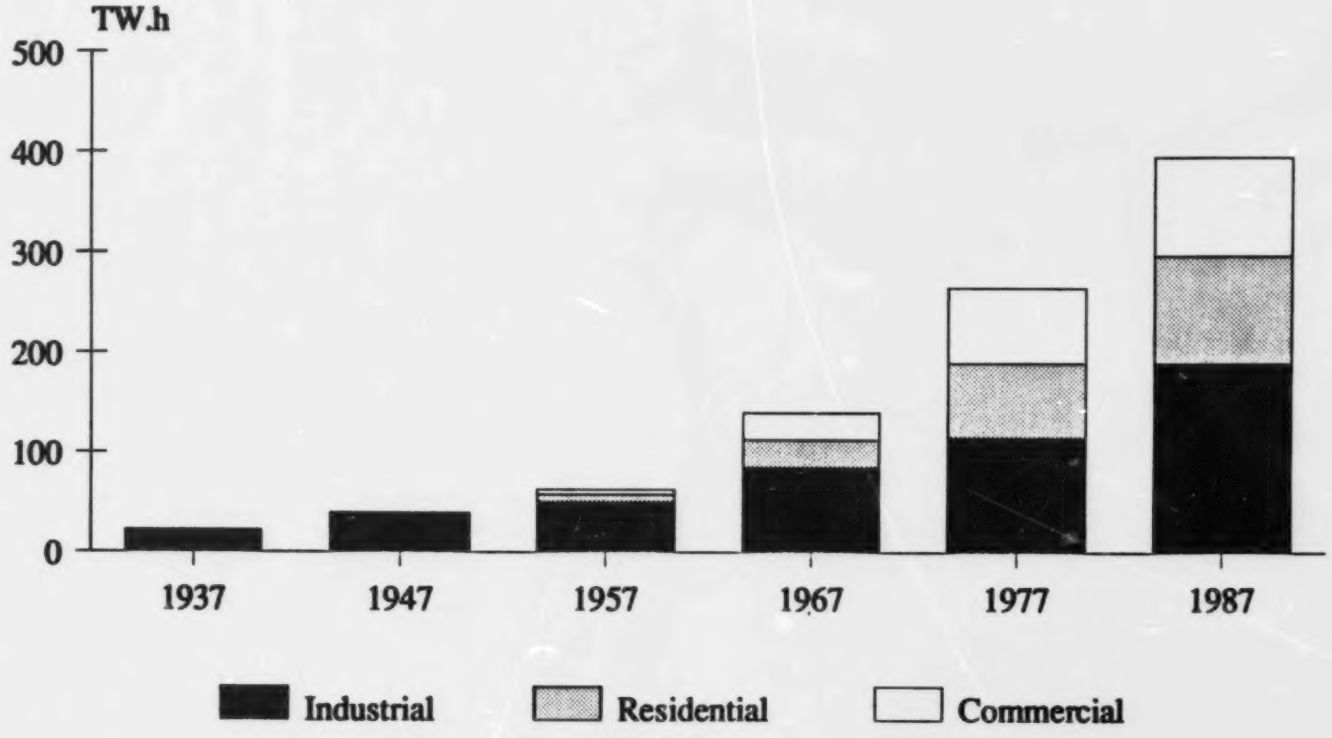
Electricity Demand Growth by Decade
Canada, 1920 - 1987



SOURCE: Historical Statistics of Canada, Electric Power in Canada.

Figure A.5

Electricity Consumption by Sector
Canada, 1937 - 1987



SOURCE: Electric Power Statistics: Quarterly Report on Energy Supply and Demand in Canada.

total revenues obtained from electricity sales. Between 1931 and 1940 in Quebec, for example, residential, commercial, farm and street-lighting sales accounted for only 4 percent of total electricity consumption, but contributed between 30 and 35 percent of all electricity revenues garnered by the utilities.[34] To be sure, the much higher prices charged to residential and commercial customers in part reflected the higher unit transmission costs associated with servicing these markets, but the pricing regime of the time was also a function of the structure of ownership in the electricity industry. The monopoly power enjoyed by most private utilities of the time allowed them to reduce prices for industrial users in order to stimulate demand, while keeping prices much higher for the "captive" residential and commercial sectors, whose consumption was seen as relatively price-inelastic.

Those regions of the country which enjoyed relatively low rates for non-industrial users were generally the ones in which public and privately-owned utilities competed directly. In Winnipeg, for example, the price of electricity for urban customers fell almost overnight from 10 cents per kilowatt-hour to 3.5 cents in the fall of 1911, when the city-owned Winnipeg Hydro Electric System began competing directly with the monopolistic Winnipeg Electric Street Railway Co.[35] Similarly, the evangelical Adam Beck, founding chair of the Ontario Hydroelectric Power Commission, forced his affiliated municipally-owned utilities to lower their residential and commercial prices sharply when the first power from Niagara Falls began flowing over the Commission's lines in 1910.[36] Non-industrial demand in these areas proved somewhat more responsive to lower prices than private utility owners had perhaps suspected, and the result was a more diversified demand profile for the publicly-owned firms. In Ontario, for example, domestic and commercial sales accounted for over one-fifth of total electric energy consumption in 1931, as opposed to less than 4 percent in Quebec.[37]

The economies of scale inherent in the hydroelectric facilities of the day, however, were so massive that even privately-owned utilities were able to reduce prices for all classes of customers, while increasing their profits at the same time. Electricity rates in most major population centres in Canada had fallen to about 3 cents per kilowatt-hour or lower by the time of the depression of the 1930s (although in smaller cities and rural areas, prices were still very high, ranging up to 35 cents in some areas).[38] Prices would stay at that level in nominal terms until the late 1960s, when inflation and rising interest rates forced utilities to seek their first-ever rate increases.

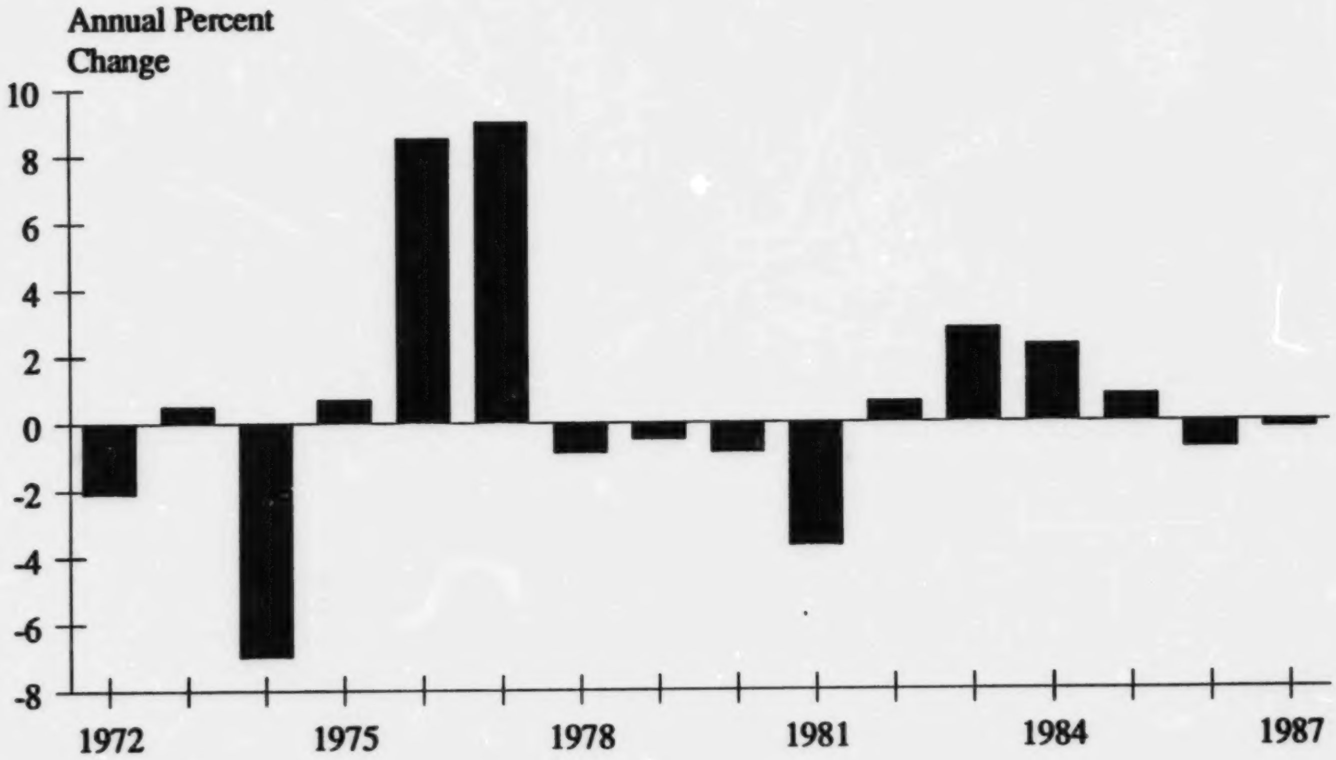
Real electricity prices, therefore, fell almost continuously from the 1920s until the energy price shocks of the 1970s, and there is little doubt that this steady price decline contributed greatly to the massive growth in electricity demand experienced during this period. Since the dramatic energy price shocks and subsequent inflation of the 1970s, electricity has become a somewhat more expensive product in real terms (see Figure A.6). Real electricity prices fell substantially in 1973 and 1981, as regulated electricity rates lagged behind inflation in the rest of the economy. Sharp price increases in the 1976-1977 and 1983-1985 periods more than made up for this lost ground; since 1985, electricity prices in most provinces have roughly kept pace with inflation.

The continued growth of electricity consumption through the 1960s and 1970s was the result of rapid economic and population growth during this period, and of the success of the electricity industry in winning markets traditionally held by competing fuels. Utilities continued to offer significant price and volume discounts to users in the industrial sector, where interfuel competition has traditionally been the sharpest. Further gains were made in the residential sector through the widespread adoption of electric space and water heating in certain provinces, again often the result of special demand-building incentives offered by utilities.

Electricity's share of total energy demand continued to rise through the energy price shocks of the 1970s and 1980s (see Figure A.7), as electricity displaced expensive refined petroleum products in all sectors of the economy. Even in the era of energy conservation, many utilities continued to aggressively promote electricity in competitive, interfuel marketing battles. In certain cases, this was an attempt by utilities to resolve short-term cash flow difficulties which resulted from the excess capacity situation experienced in the 1980s. But the result of these efforts has often been the firm establishment of electricity in new markets, that will contribute to future demand increases for years to come. Conversely, some utilities have more recently become active in conservation-oriented demand management, offering various incentives to either encourage customers to reduce their electricity consumption in absolute terms, or transfer their consumption to off-peak periods. It is increasingly felt that conservation efforts such as these offer utilities an opportunity to flatten out their demand profiles and postpone future expenditure on capacity additions.

Electricity demand in Canada today is divided relatively evenly between the industrial and the commercial and residential sectors (see Table A.1). The industrial sector consumes 42 percent of

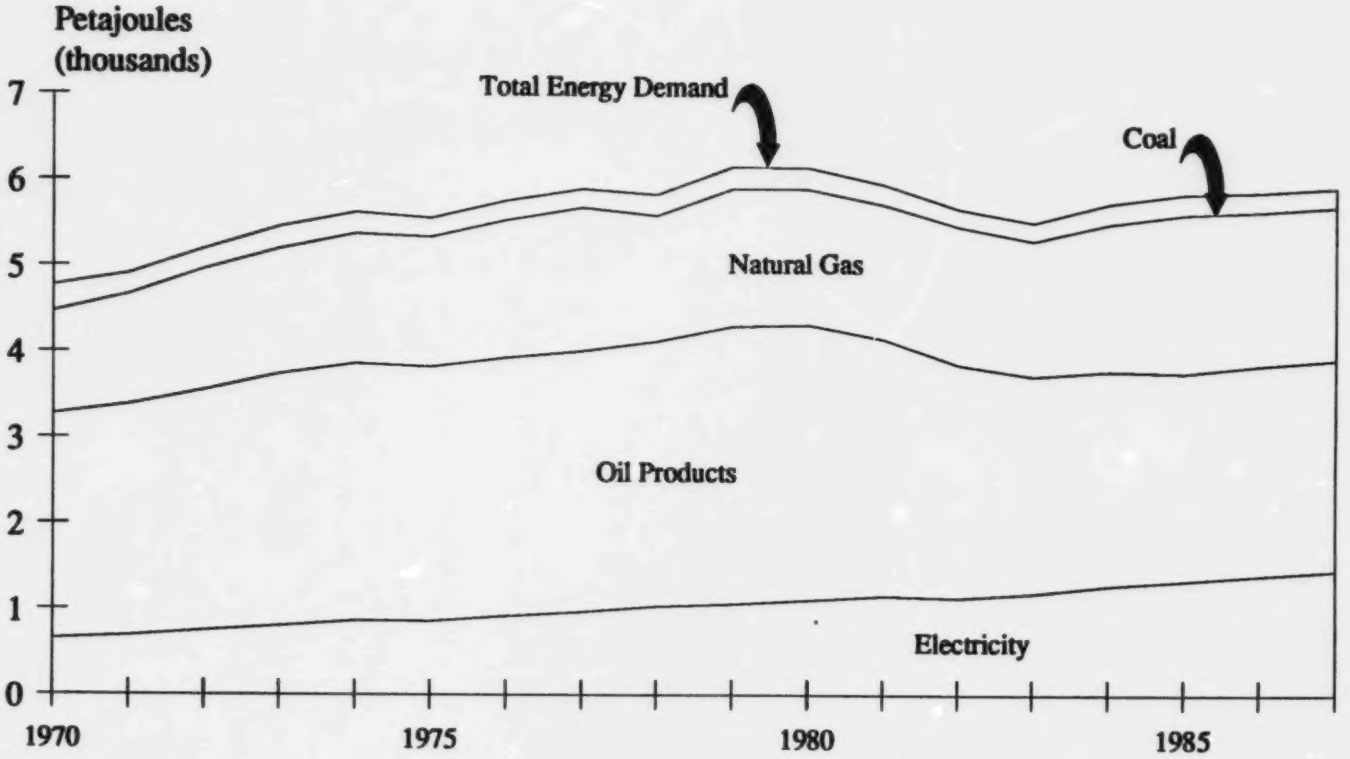
Figure A.6
Real Electricity Price Changes
Canada, 1972 - 1987



SOURCE: Consumer Prices & Price Indexes.
Statistics Canada. Based on average
Canadian residential electricity bills.

Figure A.7

Final Energy Consumption by Fuel
Canada, 1970 - 1987



SOURCE: Statistics Canada Quarterly Report on Energy Supply-Demand.
Note: Natural gas includes LPGs.

TABLE A.1

ELECTRICITY CONSUMPTION BY SECTOR CANADA, 1987

Sector	Consumption (TW.h)	Share of Total (%)
Producer Consumption and Losses	36.3	8.3
Industry		
Pulp, Paper and Sawmills	53.2	12.1
Smelting and Refining	36.2	8.2
Mining	23.8	5.4
Chemicals	17.9	4.1
Iron and Steel	10.0	2.3
Other Manufacturing	44.2	10.1
Sub-Total	185.2	42.1
Transportation	3.0	0.7
Residential		
Residential	111.6	25.4
Agricultural	7.7	1.8
Sub-Total	119.3	27.1
Commercial		
Trade and Commerce	83.7	19.0
Public Administration	12.3	2.8
Sub-Total	95.9	21.8
Total Domestic Consumption	439.7	100.0

SOURCE: Statistics Canada, Electric Power Statistics, Catalogue No. 57-202, Volume II (Ottawa: Minister of Supply and Services Canada, various years).

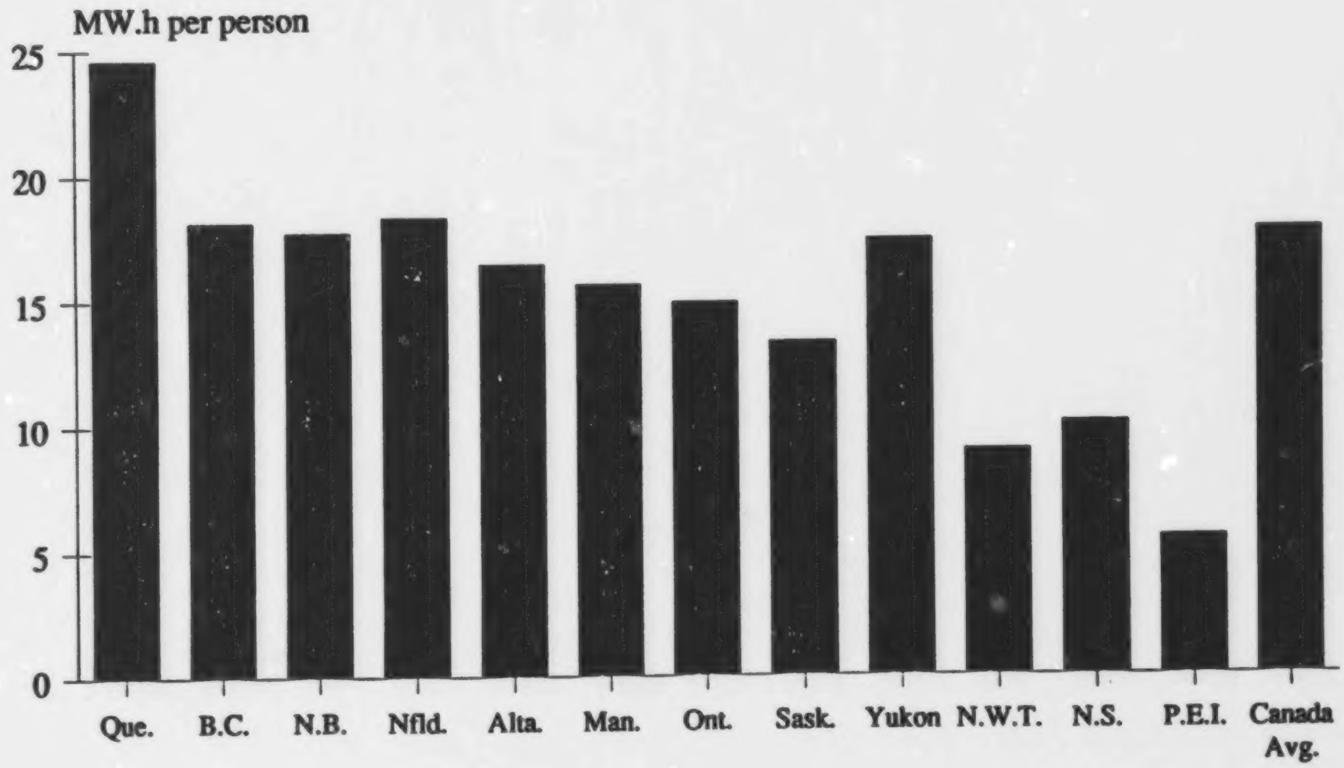
all electricity used in Canada, and losses within the electricity system itself consume another 8 percent. The pulp and paper and non-ferrous metal industries (most importantly aluminum production) are still the largest industrial energy consumers, together accounting for about one-half of all electricity demand in the industrial sector. The remaining 50 percent of demand is split between residential and commercial applications. The transportation sector, which was one of the first sources of commercial electricity demand in Canada, is now an insignificant power consumer in most parts of the country.

There exist very large regional differences with respect to the role played by electricity in each provincial economy. Per capita consumption in the most electricity-intensive province, Quebec, is more than four times greater than per capita demand in Prince Edward Island (see Figure A.8). Some provinces have traditionally consumed more electricity than others, relative to the size of their populations and economies, because of a variety of factors: lower electricity prices, greater availability of supply, colder climate, a concentration of electricity-intensive industries, and less-ready access to substitute fuels such as natural gas. Less electricity-intensive provinces, such as most of the Atlantic and Prairie provinces, have traditionally consumed very little electricity in "optional" or secondary applications such as residential space and water heating--relying instead on natural gas and/or heating oil to meet these applications.

A.5 Public Ownership and Regulation

One of the most noteworthy facets of the Canadian electricity industry is the predominance of publicly-owned utilities amongst the ranks of electricity producers. Provincial Crown corporations and municipally-owned utilities together account for over 90 percent of all energy produced by Canadian electric utilities; if the generation of privately-owned industrial producers is considered, then public utilities supply about 85 percent of all electricity generated in Canada. Those investor-owned electric utilities still in existence are subject to extensive regulation by public utility boards and other bodies, as are most of the publicly-owned utilities. In light of the experiments with privatization and deregulation that have been carried out in several Canadian industries in recent years, it is useful to review the motives behind the rise of public ownership and regulation in the Canadian electricity industry and to examine their relevance in the modern economy.

Figure A.8
Per Capita Electricity Consumption
Canada, 1988



SOURCE: EMR Canada, Electric Power in Canada 1987.

The earliest efforts to establish public ownership in the electricity industry were undertaken by municipal governments in many parts of Canada at the turn of the century.[39] In some cases, these endeavours were sparked by anger at the high prices and/or poor service characteristic of many of the private electricity monopolies of the time. In other cases, municipal entry into the electricity business was seen as a natural outgrowth of the expansion of other civic services, such as water and sewer services, and were not the result of an anti-business sentiment at all. In 1902, for example, the Edmonton city council decided to purchase the assets of the Edmonton Electric Lighting and Power Co., which had operated a small thermal generating system for 11 years, for a total of $13,500.[40] This system has grown to become the largest municipally operated generating utility in Canada, with installed capacity of almost 1000 MW and generation in 1987 of 481 GW.h.[41]

Four years later, in 1906, the City of Winnipeg established the Winnipeg Hydroelectric System. This move was taken in response to the emerging monopoly power of the Winnipeg Electric Street Railway Co., which had purchased eight rival firms since its incorporation in 1892, and had created a monopoly over electric light and power, urban transit and gas distribution in the city.[42] The two firms began to compete directly for customers in 1911, when the civic utility completed its Pointe du Bois generating system. As noted in the preceding section, the price of electricity in Winnipeg immediately fell by two-thirds, from 10 cents to 3.5 cents per kilowatt-hour. The two firms competed with each other until 1952, when the private utility was nationalized by Manitoba Hydro; its assets within the City of Winnipeg were subsequently sold to Winnipeg Hydro, which today ranks as the second-largest municipally-owned generating utility in Canada.

Other municipally-owned generating systems were formed in numerous cities in various provinces between 1900 and the outbreak of World War I, particularly on the prairies. For the most part, however, these localized attempts to establish public electricity systems were not successful. In some cases, cities were blocked by provincial legislation governing the municipalities which, in some provinces, prohibited direct competition between city-owned operations and private investors.[43] More often, civic governments were inhibited by a lack of capital and/or a lack of suitable and accessible hydroelectric sites, both of which were necessary at the time to construct modern generating facilities able to compete with the well-established private monopolies.

It is, therefore, not surprising that the first successful program to develop a truly large-scale "public power" network would be initiated at the provincial level, with the creation of the Ontario Hydroelectric Power Commission in 1906. The initial mandate of the Commission, chaired by Adam Beck, was not to generate its own electricity. Rather, it was directed to negotiate a bulk purchase of firm power from one of the three new developments on the Canadian side of Niagara Falls (which for the most part had been established to serve the export market), and then resell this power on favourable terms to municipally-owned distribution systems. This rather innocuous undertaking was successfully carried out in 1910, when the Commission finished the construction of its 110-kV transmission line from Dundas, Ontario to Niagara Falls, and commenced power distribution to the first ten municipalities which had agreed to join the cooperative system.

The political controversies that surrounded this development, set in motion forces that eventually established Ontario Hydro (as it was officially renamed in 1974) as the largest Crown corporation in Canada. The private utilities at the time--especially the Toronto Electric Light Co., which controlled one of the three developments at Niagara--fiercely resisted the move towards a publicly-owned distribution system. Beck, in turn, mobilized an impressive extra-parliamentary "public power" movement, centred in the growing industrial belt of southwestern Ontario, to demand cheap access to the new marvels of hydroelectric power. Beck's arguments won over a large majority of public opinion in the provincial election of 1905 and the municipal elections of 1907, giving him the political mandate to challenge the private utilities more aggressively than had been initially envisioned. He ordered the municipal utilities to sharply cut prices to reflect the lower costs of the Niagara power, thus escalating the competition with private utilities. In Toronto, the largest market in the province, the new municipal distributor started supplying its own power in 1911 at a price 40 percent lower than the competing Toronto Electric Light Co.; by 1918, the average price had fallen to less than 1 cent per kilowatt-hour, and the municipal utility had captured over two-thirds of all sales in Toronto.[44]

Emboldened by his successes, and with his argument strengthened by widespread power shortages during World War I, Beck convinced the provincial government to allow the Commission to develop its own generating capacity. In 1917, the Commission purchased the Ontario Power Company's generating station at Niagara Falls. The same year, the Commission commenced construction on its own plant at the Falls--the massive Queenston-Chippewa station, which would boast a capacity of 392 MW when its last units were connected in 1930.[45] The writing was on the wall for the private utilities in the province. They fell one by one--generally through attrition, rather than through expropriation or nationalization. By 1915, a total of 115 municipalities had enlisted in Beck's cooperative public power scheme. When the distribution facilities of the once-mighty Toronto Electric Light Co. were finally taken over by the City of Toronto in 1922, the establishment of Ontario Hydro as the dominant supplier of electricity in Ontario--and one of the largest utilities on the continent--was complete.

Given the vociferousness of Beck's campaign against the private utilities, it would be easy to conclude that the creation and growth of Ontario Hydro reflected a strong anti-business attitude on the part of the Ontario government and the supporters of public power. This would be a mistake. The most influential base of support cultivated by Beck during his campaign was the community of mid-sized industrialists that had sprung up in southwestern Ontario and which was worried that the power of Niagara Falls was being monopolized for export to the U.S. market or for the profits of Toronto utility magnates. Far from being an expression of socialist or statist ideology, public power was seen as a crucial instrument of economic development policy in a strongly market-oriented context. As one historian of the time has stressed,

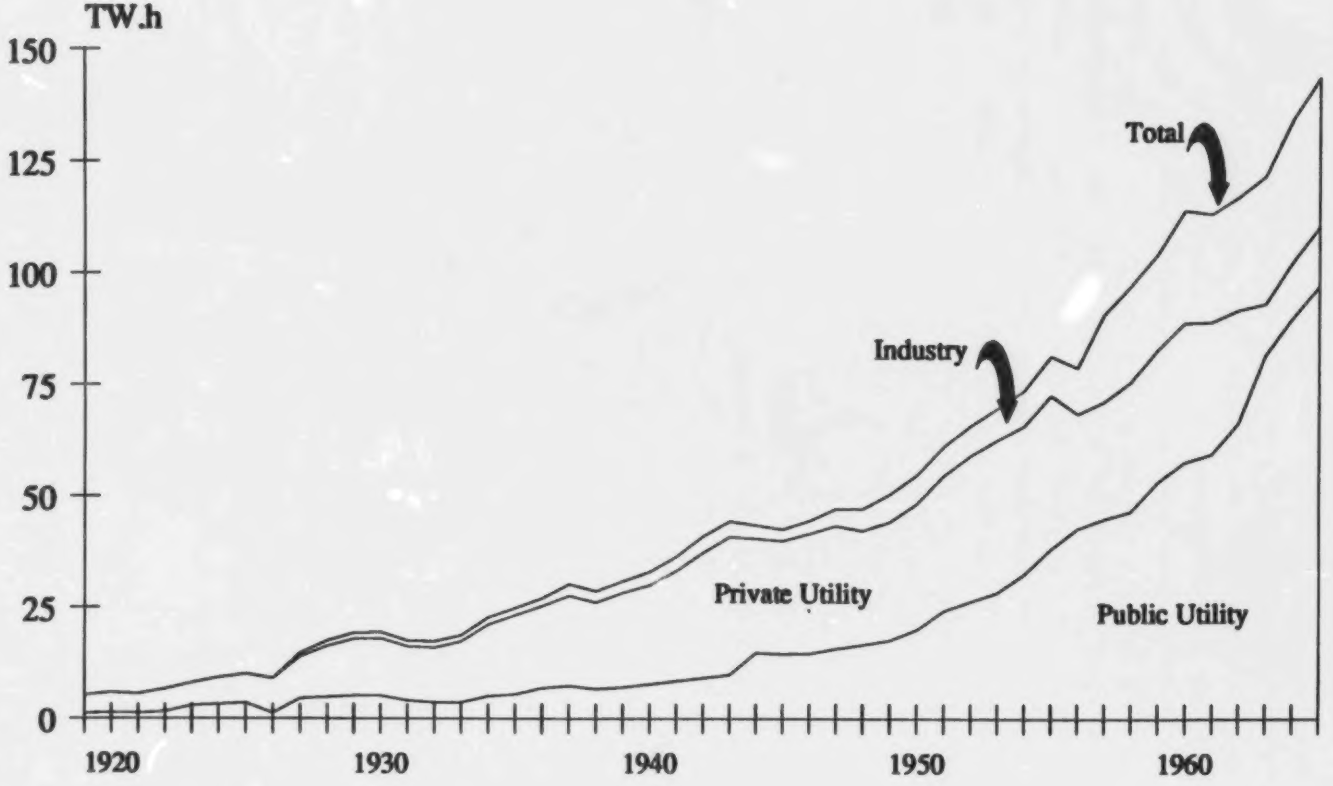
> From the outset the crusade for public power was a businessmen's movement; they initiated it, formed its devoted, hard-core membership and, most importantly, they provided it with brilliant leadership. By the phrase `the people's power', the businessmen meant cheap electricity for the manufacturer, and it was assumed that the entire community would benefit as a result ... The socially and politically influential manufacturers turned readily to public ownership primarily because the private electric companies at Niagara refused to guarantee them an immediate, inexpensive supply of a commodity on which they believed their future prosperity depended.[46]

The success of the Ontario Hydro experience was watched carefully in other provinces, but it would be several decades before public ownership was entrenched as the dominant organizational form in the rest of Canada. Provincial electricity commissions were established in four other provinces by 1928--Nova Scotia, Manitoba, New Brunswick and Saskatchewan--but due to a shortage of capital and a less aggressive approach to dealing with the private utilities, these commissions were not at first able to develop significant amounts of their own generating capacity. The Manitoba Power Commission operated in a fashion similar to the original strategy of Ontario Hydro: it purchased bulk power from a private producer (the Winnipeg Electric Street Railway Co.), and resold it to remote communities which the private utilities themselves were unwilling to serve.[47] Far from threatening the private utilities, the Commission was a significant and reliable customer. In Nova Scotia, on the other hand, the provincial commission took the opposite approach, supplying bulk power to private utilities for retail distribution. In 1919, immediately after its inception, the Nova Scotia Electric Commission started construction of a generating station and transmission line to Halifax, but the utility could not convince the City of Halifax to build its own distribution network to accept the power. Consequently, the Commission had no option but to sell the bulk power at low rates to the Nova Scotia Tramways and Power Co., which profited substantially through the resale of the power to the captive Halifax market.[48]

The New Brunswick Electric Power Commission was the only provincial utility which followed Ontario Hydro's strategy of building an integrated, publicly-owned system, with moderate success. Its first generating station was constructed on the Musquash River in 1923, with a 69-kV line linking it to Moncton and to a municipally-owned distribution system in St. John. A subsequent price war with private utilities in those cities sparked great demand increases,[49] but the Commission steered clear of an all-out confrontation with the utilities by agreeing, in 1925, to start purchasing a large share of its power supply from the same private utilities with which it was competing.[50] Through the inter-war years and World War II, therefore, publicly-owned utilities accounted for a very small share of total electricity generation in Canada (see Figure A.9).

Following World War II, however, the development of public power in Canada accelerated dramatically. The government of Quebec set the tone in 1944 when it nationalized the assets of the Montreal Light, Heat and Power Co., creating Hydro-Quebec. The monopolistic practices and notoriously poor service of Montreal Light, Heat and Power had long sparked complaints among electricity consumers in Montreal. In 1909 the provincial government had established the

Figure A.9
Generation by Type of Ownership
Canada, 1919 - 1965



SOURCE: Historical Statistics of
Canada, Series Q75-80.

Montreal Electricity Commission to investigate these allegations and oversee the firm's rates, but the company had managed to escape serious attention by periodically reducing its rates (even though profits continued to rise, thanks to even greater reductions in costs). Its lack of cooperation with municipal and provincial authorities--by refusing to disclose its financial statements, and failing to lower rates voluntarily in line with the recommendations of a 1934 provincial commission--led to its demise in 1944.[51]

The newly-elected CCF government of Saskatchewan nationalized most of that province's electricity industry 4 years later, in 1948, while Manitoba Hydro purchased the assets of the Winnipeg Electric Co. in 1952. With two other major nationalizations in the early 1960s--the B.C. government's purchase of the B.C. Power Corporation in 1962, and Hydro-Quebec's purchase of eight private utilities in 1963--the dominance of public power in Canada was established. The only significant expansion in public ownership since 1963 has taken place in the Atlantic provinces: the formation of the Newfoundland Power Commission in 1964, its purchase of Brinco's share of Churchill Falls in 1974, and the Nova Scotia Power Commission's acquisition of the N.S. Light and Power Co. in 1972. Only Alberta and Prince Edward Island escaped the wave of public acquisition that followed World War II; in all other provinces, publicly-owned firms became the dominant suppliers of power. Today, investor-owned utilities are responsible for only 7 percent of all electricity generated in Canada (see Table A.2), with the output of private industrial generators contributing another 7 percent.

With only a single exception--the creation of SaskPower by the CCF government in Saskatchewan--none of these take-overs of private corporations were accompanied by socialist rhetoric or by a widespread philosophical opinion that state ownership must play a central role in economic development. Even public anger at the high prices of private utilities was a relatively minor element of the political environment that promoted the growth of public power. Most of the nationalizations were carried out by business-leaning governments, which justified their actions on pragmatic, flexible, and non-ideological grounds. In each case, the reasons for nationalization were complex and varied from province to province. Some common themes, however, can be identified:

- Promotion of industrial development: In general, this has probably been the most important factor behind the rise of public ownership in the Canadian electricity

TABLE A.2

PRIVATE ELECTRICITY GENERATION IN CANADA
1987

Utility	Province	Generation (GW.h)	Share of Provincial Generation (%)	Share of Canadian Generation[a] (%)
Major Private Utilities				
TransAlta Utilities Corp.	Alta.	26 283	71.5	5.5
Alberta Power Ltd.	Alta.[b]	6 674	17.7[c]	1.4
West Kootenay Power & Light	B.C.	1 518	2.4	0.3
Newfoundland Light & Power	Nfld.	331	3.4[d]	0.1
Maritime Electric Co. Ltd.	P.E.I.	164	100.0	-
Sub-Total		34,970		7.3
Industries		34 230		7.1

SOURCES: Company annual reports and Energy, Mines and Resources Canada, Electrical Power in Canada, 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a] Including generation by industry.
[b] The company and its subsidiaries also generate electricity in the Yukon and Northwest Territories.
[c] Share of total generation in Alberta, Yukon and Northwest Territories.
[d] Excluding Churchill Falls exports to Quebec.

industry. It was one of the key motives for Ontario Hydro's formation, and the provision of least-cost power to promote industrial growth continues to be a top priority for many provincial Crown utilities.

- Reduction of prices; protection of consumers: This classic anti-monopoly justification for public ownership has been relatively insignificant in the Canadian experience. It was a primary motive in some of the earlier efforts to establish municipal utilities, and was important in Quebec's 1944 purchase of Montreal Light, Heat and Power.

- Reduction of federal taxation: The exemption of Crown corporations from federal corporate income taxation created a rather accidental motive for the nationalization of electricity companies. Provinces with privately-owned utilities made a greater contribution to federal coffers, through payment of these taxes, than provinces with public utilities. This was an important reason for the nationalizations in Quebec and B.C. in 1962-1963, following their failure to convince the federal government to stop the taxation of private utilities. The issue also played a role in Newfoundland's purchase of the Brinco share of the Churchill Falls development.[52]

- Construction of very large or risky electricity facilities: Public utilities have on occasion been charged with the construction of electricity projects that private firms deemed financially unfeasible or unattractive. Ontario Hydro's commitment to connect southwestern Ontario to the generating stations at Niagara Falls--a task which no private investor was willing to carry out--was the key reason for its early success and popularity. Since then, government's desire to proceed quickly with megaprojects in B.C. and Quebec played a secondary role in utility nationalizations in those provinces, while a wish to subsidize rural electrification was a factor in the creation of early public power commissions on the prairies.

- Protection of national interests: The first two generating facilities on the Canadian side of Niagara Falls were owned by Americans and designed to serve the American market. A concern with protecting Canadian interests in the development of the falls was an important factor behind the early public support for Ontario Hydro. Since that time, nationalism has been a relatively unimportant factor in the growth of public ownership. One exception to this rule might be in Quebec, where the high degree of U.S. ownership of the electricity industry, together with the overwhelming predominance of anglophone technical and managerial

> staff, were important concerns leading to the nationalization of private utilities.

It is clear from this list that the development of public ownership in Canada's electricity industry was the result of political and economic phenomenon much more complex than a simple anti-monopoly concern with the excess profits of private utilities. Public ownership was generally sparked by a conjuncture of varying social and economic conditions, and was generally carried out in a surprisingly non-ideological atmosphere. Where public ownership has not evolved into the dominant organizational structure--most especially in Alberta--some have argued that this is because of a firmer commitment to values of free enterprise on the part of both politicians and the population at large, but this observation has not been universally accepted; government has still played an important indirect role in shaping and regulating the electricity industries of these provinces.[53]

Some of the motives for public ownership of the electricity system listed above could quite conceivably have been served equally well by regulation, rather than by outright nationalization. This is especially true of the issue of consumer protection from monopolistic pricing practices. Why did most provinces opt for public ownership as a means of controlling the practices of the industry, rather than rate-of-return regulation as it is practised in other industries today? By 1915, a majority of provinces had established public utilities commissions to monitor and regulate the behaviour of firms in the transportation, communication and energy industries. Fairly quickly, however, it became clear that these early regulatory structures were rather meek and powerless;[54] they lacked the legislative authority and technical expertise required to effectively regulate rates-of-return in the fashion that became more common in the 1960s and 1970s. At the time that most ventures into public ownership were initiated, therefore, direct competition with a private utility was generally seen as the only effective means of reducing prices and making the full potential of electric technology available to the majority of the population.

Another factor that is important in explaining the preference for public ownership over regulation is the strategic role that electricity supply has played in the economic development policies of most provinces.[55] While rate-of-return regulation can in theory prevent private monopolies from garnering excess profits, it cannot be expected to force utilities to undertake mega-investments that it otherwise would choose to decline, nor to offer power at cost or below-cost to rural or industrial consumers in the interests of job creation and industrial diversification. The provincial Crown utilities have often fulfilled these or similar functions at various points in their histories.

Since the last major nationalizations of private utilities--in Newfoundland and Nova Scotia in the early 1970s--there has been no further expansion of public ownership in Canada's electricity industry. Indeed, in certain parts of the country, there has been a limited tendency towards a renewal of private ownership of electrical facilities. In British Columbia, for example, the provincial government has announced a new policy favouring long-term contracts with private power producers (including Alcan, which owns the massive Kemano hydroelectric facility) as a preferred means of meeting future capacity requirements. The government of the Yukon recently hired a subsidiary of Alberta Power, the second-largest private electric utility in Canada, to manage its electricity generation assets, which were transferred to territorial control from the federal Northern Canada Power Corporation in 1987. An increasingly vocal community of small power producers has been lobbying in many parts of Canada for better commercial conditions governing their sale of excess power to larger utilities. Behind this limited move towards privatization lies a concern with the efficiency of public utilities, both in an operational sense and more importantly in terms of the return on the vast quantities of capital which have been invested in the Crown utilities.

A.6 Trade in Electricity

International electricity trade has played a critical role in the development of the Canadian electricity system, dating back to the first generating stations constructed on the Canadian side of Niagara Falls. The first two plants at Niagara--the Canadian Niagara and Ontario Power facilities--were designed explicitly to service the export market. The third station, built by the Electrical Development Co., was intended both for power exports and for sales to the Toronto area. All three operations were required by the provincial government to reserve 50 percent of their output for Canadian buyers, but until the Ontario Hydroelectric Power Commission completed its 110-kV line to Dundas, Ontario in 1910, no company was willing to build the transmission facilities required to deliver the Niagara power to Canadian markets. Exports from the Niagara generating stations took place over aerial cables strung across the Niagara River, or through a series of transmission lines strung across the bottom of the Rainbow Bridge at Niagara Falls, New York.[56] The first Canada-U.S. electricity interconnection--a 12-kV line--was completed in 1901. More lines were soon added in the Niagara Falls area, while in 1905 an interconnection was constructed between New Brunswick and Maine, followed by others in Quebec and Manitoba.[57] Early electricity exports from Canada were regulated by the 1907 Electricity and Fluid Exportation Act, which required federal government approval for all power sales to the U.S.

Exports during this early period of electrical development generally took place in the form of long-term firm contracts. A prearranged and reliable export contract with a U.S. customer--either an American utility or a major industrial electricity consumer--was key to the construction of several early hydroelectric developments in Canada. In some of these cases, the firm that built and owned the generating plant in Canada was a subsidiary of the U.S. firm that accepted the power. This was true of the two American-owned developments at Niagara Falls: the Canadian Niagara Power Co. was a subsidiary of the Niagara Falls Power Co., while the owners of the Ontario Power Co. were several of the most prominent industrialists of Buffalo, New York, who intended to purchase most of the electricity for their own plants.[58] This pattern of ownership also led to the development of the first 56-MW generating facility at Cedars Rapids, Quebec. The Aluminum Company of America signed an 85-year contract in 1912 with a wholly-owned Canadian subsidiary, the Cedars Rapids Transmission Co., to build the plant and supply electricity to Alcoa's factory at Massena, New York. Delivery of power under this arrangement began 2 years later.[59] The first electricity transactions between Maine and New Brunswick also took place between a U.S. firm and its Canadian subsidiary. In 1905, the Maine and New Brunswick Electric Power Co. began to supply electricity from its hydroelectric station at Aroostook Falls, New Brunswick to its parent firm in the U.S., the Maine Public Service Co.[60]; since 1917, the two firms have been run as a single entity.

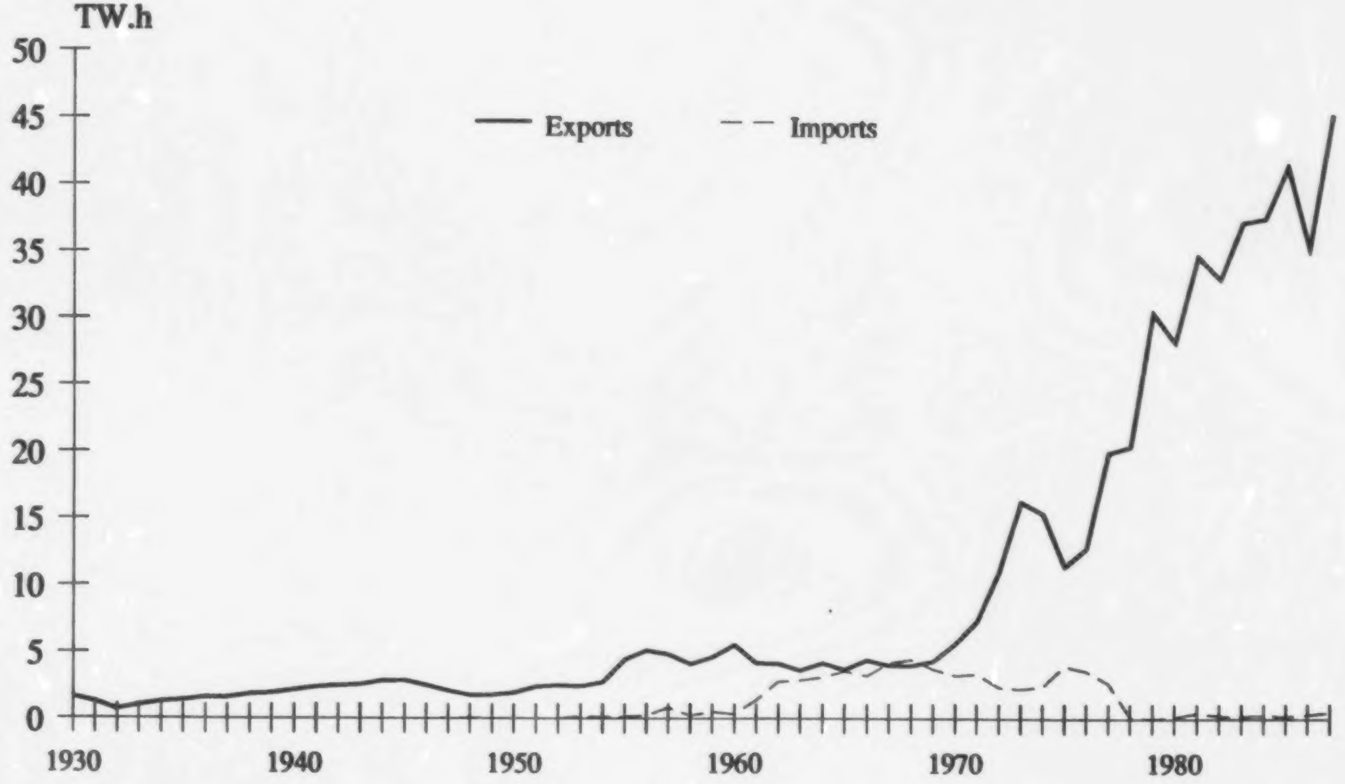
The volume of these initial exports was not large by present standards, but they accounted for a large share of Canada's early electricity production. As the distribution systems in both countries gradually became more comprehensive, the initial firm export sales were supplemented by a growing number of small interconnections designed to service small or isolated load centres on opposite sides of the border. Canadian energy exports to the U.S. increased slowly between 1920 and 1950 but, as a share of total generation in Canada, they fell considerably in relation to the spectacular increases in Canadian generating capacity. By the 1920s, increases in domestic consumption had become the main stimulant for new hydroelectric developments in Canada, and utilities were no longer oriented towards the export market.

The increasing size and sophistication of electric systems on both sides of the border in the years following World War II contributed to an evolution in the nature of power trade between the two countries. Dedicated firm exports still made a small contribution to total Canadian sales to the U.S., but a larger volume of energy began to flow on a shorter-term, more flexible basis. Utilities found that greater interchange capacity allowed for economy sales, emergency backup and seasonal exchanges that could enhance the reliability and efficiency of the electricity systems in both countries. This was reflected in the formulation of a new National Power Policy by the federal government in 1963, which explicitly encouraged cross-border trade in electricity as a means of improving both the efficiency and the reliability of provincial electric networks.

By 1960, exports reached a peak of some 5500 GW.h, earning close to $14 million in revenues, still less than 5 percent of total Canadian generation. It was during the 1960s, however, that Canada began to import significant quantities of electricity from the United States, the result of the tight supply situation faced at the time by many Canadian utilities (see Figure A.10). In 1967 and again in 1968, Canada was actually a small net importer of electricity. By 1970, however, Canadian generating capacity had caught up with domestic demand, and these imports fell off. Later in the 1970s and 1980s, the volume of electricity exported by Canadian utilities skyrocketed, increasing by 1987 to a level almost ten times the exports of 1970.

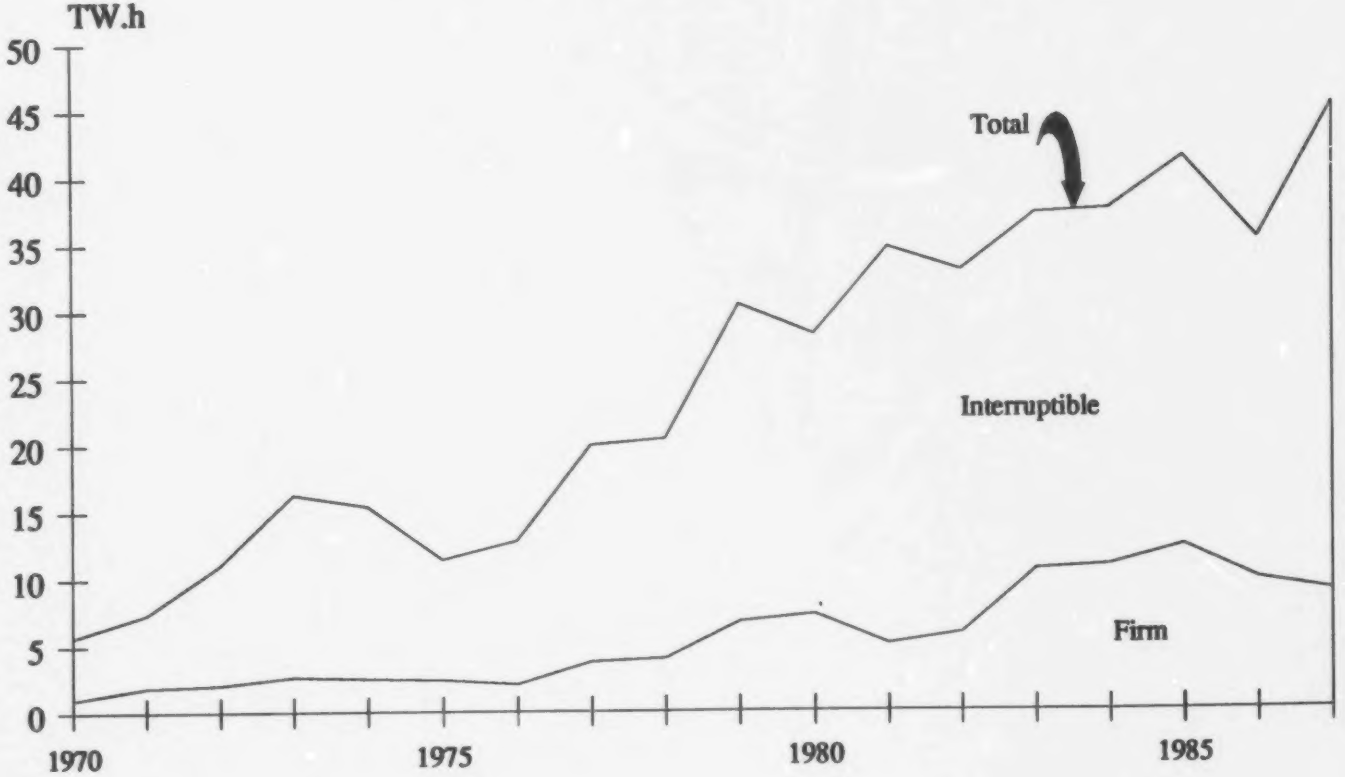
Most of this new wave of exports to the U.S. was in the form of interruptible energy sales (see Figure A.11), as Canadian utilities--many of which were carrying large amounts of excess capacity due to the demand slowdown of the early 1980s--aggressively promoted bargain-basement sales of economy power to neighbouring U.S. utilities. Electricity trade between the two countries has now become an important component of Canada's trade balance, generating over $1 billion per year in net revenues. More recently, some Canadian utilities have been attempting to tap more permanently into the U.S. market with a new generation of firm export contracts, often on the strength of export-dedicated generating capacity within the province. This allows the utilities to receive a much higher average price for their export sales than is generated by interruptible exports, but it also requires that more careful attention be given to ensuring that the needs of domestic customers will still be satisfied in the long term.

Figure A.10
Canadian Electricity Exports and Imports
1930 - 1987



SOURCE: Historical Statistics of Canada:
Electric Power in Canada.

Figure A.11
Canadian Electricity Exports
1970 - 1987



SOURCE: EMR Canada, Electric Power in Canada.

Interprovincial trade between Canadian utilities has been much less significant historically than has contracted export power. The first major electricity interconnection between Canadian provinces was not completed until 1928--a 230-kV connection between Ontario and Quebec that was built almost 30 years after the first Canada-U.S. interconnection was established.[61] It will only be in 1989, with the completion of a 230-kV connection between Alberta Power and SaskPower, that a cross-Canada electricity grid will have been established. Canadian utilities have traditionally developed their systems in a self-reliant fashion, relying on interprovincial supply for only short-term or emergency back-up, and not for long-term reliable supplies.

Interprovincial trade in electricity totalled just under 50 000 GW.h in 1987, roughly equal to the volume of exports to the U.S. Close to two-thirds of this interprovincial trade, however, is accounted for by a single transaction: the annual sale to Quebec since the early 1970s of over 30 000 GW.h of firm energy from Newfoundland's Churchill Falls development.[62] Since the precedent-setting Churchill Falls arrangement, there have been a few smaller long-term supply arrangements that rely on the flow of electricity across provincial borders--most notably trade between Prince Edward Island, New Brunswick, and Quebec--but most utilities in Canada continue to adopt an independent approach to the development of future electricity supplies.

A.7 Conclusion

This historical review has attempted to recap the crucial historical developments that have culminated in the creation of the Canadian electricity system as it presently exists. Tables A.3 and A.4 display important dates in the development of Canadian electric power.

We have seen that the evolution of electricity supply, the changing nature and volume of electricity consumption, and the rise of public ownership in the industry were the result of a complex interrelation of economics and politics, one that has played a crucial role in shaping the pattern of economic and industrial development in Canada. On the supply side, Canada's geography--with its wealth of hydroelectric resources--exerted a powerful influence on the nature of the industry, with electric utilities oriented towards the development of hydro sites located increasingly far from the major population centres. On the demand side, it has been shown that the industrial sector

TABLE A.3

IMPORTANT DATES IN THE DEVELOPMENT OF ELECTRICITY SUPPLY

1880- 1900	Early electricity requirements in Canadian cities are met by small, unconnected thermal plants, usually with generating capacity of a few hundred kilowatts or less. Some small hydraulic generating stations are also built, where water conditions adjacent to urban areas or industrial sites are favourable.
1883	First electric street lighting system in Canada begins operation in Hamilton, Ontario.
1885	First electric streetcar system in Canada begins operation in Toronto, Ontario.
1893	The first electric generating station on the Canadian side of Niagara Falls begins operation. It was a 2-MW unit supplying electricity to the Niagara-area tramline of the International Railway Company.
1897	First long-distance transmission of electricity in Canada, over an 18-mile 11-kV line to Trois-Rivieres, Quebec from the North Shore Power Company station on the Batiscan River.
1901	The Canadian Niagara Power Company begins producing 90 MW of electric power on the Canadian side of Niagara Falls. Most of the power was exported over a 12-kV line to Buffalo, N.Y.
1902	The Ontario power Company begins construction of a 25-MW generating station on the Canadian side of Niagara Falls; the station was completed in 1905.
1903	The Electrical Development Company begins construction of a 125-MW station at Niagara Falls, Ontario.
1903	The first power is delivered over a 90-mile 50-kV transmission line to Montreal from the Shawinigan Power Company's new plant at Shawinigan Falls, near Trois Rivieres.
1906	The first power is delivered to Toronto over a long-distance transmission line from the Electrical Development Company installation at Niagara Falls.
1906- 1910	Several major hydroelectric developments are completed by pulp and paper companies at locations in Northern Ontario and Quebec, including Kenora, Thunder Bay, Fort Frances, Sault Ste. Marie and Chaudiere Falls.
1910	Ontario Hydro completes its own 110-kV transmission line to the generating stations at Niagara Falls, and commences bulk power sales to ten municipal utilities in Ontario.
1910	The city of Medicine Hat, Alberta constructs the first natural gas-fired generating units in Canada, at the wellheads of city-owned shallow gas wells.

Continued on Next Page

TABLE A.3 (continued)

1914	The 72-MW Les Cedres generating station is completed. The first major hydroelectric development on the St. Lawrence River, it was jointly constructed by the Shawinigan Water and Power Co. and the Montreal Light, Heat and Power Co.
1928	The Winnipeg Electric Railway Company completes the 132-MW Great Falls dam and generating station, which featured the highest operating head of any hydroelectric dam in the world at the time.
1929	A 128-MW hydro station is opened at Deer Lake, Nfld., primarily to serve the Newfoundland Pulp and Paper Company's operations at Corner Brook.
1930	Ontario Hydro's Queenston-Chippewa generating station is completed at Niagara Falls; with a capacity of 392 MW, it is the world's largest power station.
1935-1939	A dramatic slowdown in additions to Canada's electric generating capacity, resulting from the effects of the Depression on electricity demand; total capacity increases at a rate of 2 percent per year between 1935 and the start of World War II, compared to an annual rate of 8 percent between 1917 and 1935.
1949	Edmonton Power opens the 60-MW Rossdale generating station, the largest thermal plant in Canada.
1951	Ontario Hydro completes a 100-MW coal-fired steam generator in Toronto, the largest single generating unit of any kind in Canada.
1953	The second stage of the Beauharnois station is completed on the St. Lawrence River, making it the first generating station in Canada with a capacity greater than 1000 MW.
1959	Construction begins on Hydro-Quebec's Manicougan-Outardes complex; when completed, the project will feature 7 generating stations with total capacity of 5500 MW, and the largest artificial reservoir in North America.
1960	The 236-MW Kelsey generating station is completed on the Nelson River, primarily to serve Inco mining operations at Thompson, Man.
1961	The Columbia River treaty is signed between Canada and the U.S., providing for the joint development and operation of hydroelectric stations in the Columbia River basin.
1962	Demonstration nuclear power plant opens at Rolphton, Ontario, with a capacity of 25 MW.
1965	For the first time in the world, electricity is transmitted at 735-kV over a line between Hydro-Quebec's Manic facilities and Quebec City.
1966	The first commercial nuclear power in Canada is produced at the 200-MW Douglas Point facility.
1966	An agreement is signed between the governments of Canada and Manitoba to jointly develop the hydroelectric potential of the Nelson River.

Continued on Next Page

TABLE A.3 (continued)

1968	The first Canadian direct current transmission line is placed in service between Vancouver Island and the mainland.
1970	Calgary Power commissions the first 375-MW unit at its Sundance generating complex; when completed, the mine-mouth facility will have total capacity in excess of 2000 MW.
1971	The first two 475-MW generating units are commissioned at the Churchill Falls development in Labrador; this station is the largest hydro development in Canada.
1971	The 556-mile +/-450-kV transmission line between Winnipeg and the Nelson River facilities is energized; this remains the highest voltage commercial transmission system in the world.
1971	The 230-MW Gentilly nuclear power station is completed, the first commercial nuclear generating station outside of Ontario.
1976	The first 800-MW generating unit is brought into service at the Bruce station on Lake Huron; when completed, the Bruce complex's 6775-MW capacity will make it the largest power plant in Canada.
1979	The first power is delivered from the giant James Bay complex in northern Quebec, which cost over $15 billion to build and has a total capacity of more than 10 000 MW.
1981	The first units of B.C. Hydro's development on the Peace River are brought into service; the combined 3100-MW capacity of the Gordon M. Schrum and Peace Canyon facilities make it the fourth largest hydro development in Canada.
1981-1987	A significant slowdown in the rate of new capacity addition, due to the slowing of demand resulting from high energy prices and the recession of 1982; capacity grows by an average of 3 percent per year during the 1980s, compared to an annual average of almost 7 percent between 1970 and 1980.
1982	The first nuclear power station in the Maritimes, the 630-MW Point Lepreau unit, is placed in service by NB Power.
1984	The first tidal generating station in North America is completed at Annapolis Royal, N.S.

SOURCE: Statistics Canada, Electric Power Statistics, Catalogue No. 57-202, Volume II (Ottawa: Minister of Supply and Services Canada, various years).

TABLE A.4

IMPORTANT DATES IN THE DEVELOPMENT OF PUBLIC POWER

1895	City of Toronto attempts to establish a municipally-owned generating plant; it is blocked by the Conmee Amendment to the Municipal Act of Ontario.
1902	City of Edmonton purchases the Edmonton Electric Light Company, which owned a single coal-fired steam generating plant, for $13,500.
1906	City of Winnipeg Hydro-Electric System is established to compete with the Winnipeg Electric Railway Company; first municipally-owned power is produced in 1911 from Point du Bois Falls.
1906	Ontario Hydro-Electric Power Commission is established; Adam Beck is appointed as the first chairman.
1907	Toronto and other municipalities in Ontario vote to establish municipally-owned distribution systems to purchase bulk power from the Ontario Hydro-Electric Power Commission.
1910	Ontario Hydro-Electric Power Commission completes long-distance transmission line to Niagara Falls; bulk power sales commence to ten participating municipal utilities. Within 5 years, a total of 110 municipal utilities join the Commission's system.
1916	Ontario Hydro-Electric Power Commission purchases the Ontario Power Company, which owned one of the three generating stations on the Canadian side of Niagara Falls.
1919	Nova Scotia Electric Commission is formed; construction commences on its first generating station and a transmission line to Halifax.
1919	Establishment of Manitoba Power Commission.
1920	Establishment of New Brunswick Electric Power Commission; power generation at its first major station, a hydro plant on the Musquash River, begins in 1923.
1921	The Queenston-Chippewa plant, the first major generating station built by the Ontario Hydro-Electric Power Commission, begins production at Niagara Falls; when the last generating unit is completed in 1930, the plant's 392-MW capacity is the largest in the world.
1922	The Toronto Electric Light Co., decimated by competition from the municipally-owned utility in that city, is purchased by the City of Toronto for $7 million.
1928	Establishment of the Saskatchewan Power Commission.
1944	Formation of Hydro-Quebec, and the nationalization of the Montreal Light, Heat and Power Company for a payment of $173 million over 3 years.

Continued on Next Page

TABLE A.4 (Continued)

1945	Establishment of the B.C. Power Commission.
1947	The New Brunswick Power Company is acquired by the N.B. Electric Power Commission.
1948	Saskatchewan Power Commission nationalizes the three largest private electric utilities in the province: Montreal Engineering, Dominion Electric, and Canadian Utilities. SaskPower is incorporated in 1950, and purchases all other private utilities in Saskatchewan by 1958.
1948	Establishment of the Northwest Territories Power Commission (later renamed the Northern Canada Power Commission), to develop electricity supply in the Yukon and Northwest Territories.
1949	Establishment of the Manitoba Hydro-Electric Board.
1952	The Winnipeg Electric Railway Company is nationalized by the Manitoba Hydro-Electric Board; the company's assets within the city of Winnipeg are subsequently sold to Winnipeg Hydro. Five other independent utilities are purchased by Manitoba Hydro in the next 8 years.
1954	Formation of the Newfoundland Power Commission.
1959	The Moncton Electric and Gas Company is acquired by the New Brunswick Electric Power Commission.
1962	The B.C. Hydro and Power Authority is created to complete the nationalization of the B.C. Power Corp., for $111 million cash and $684 million assumed long-term debt. Twelve smaller private utilities are also purchased by B.C. Hydro over the next 8 years.
1963	Hydro-Quebec nationalizes eight private utilities and 46 rural electrification cooperatives for more than $600 million cash and assumed long-term debt.
1964	Newfoundland Power Commission constructs its first major generating project, the 600-MW Bay d'Espoir hydro complex.
1972	Nova Scotia Power Commission acquires Nova Scotia Light and Power Company (and two municipal utilities in subsequent years). The Nova Scotia Power Corporation is incorporated in 1973.
1974	Newfoundland government purchases Brinco's share of Churchill Falls for $160 million, and amalgamates it with the Newfoundland Power Commission to form Newfoundland and Labrador Hydro.
1987	Northern Canada Power Commission transfers ownership of Yukon assets (valued at $95 million) to the territorial government. The Yukon government forms the Yukon Energy Corporation, whose assets will be managed by the Yukon Electric Company (a subsidiary of Alberta Power).
1988	Northern Canada Power Commission transfers ownership of N.W.T. assets (valued at $96 million) to the territorial government, which establishes the Northwest Territories Power Corporation.

SOURCE: Statistics Canada, Electric Power Statistics, Catalogue No. 57-202, Volume II (Ottawa: Minister of Supply and Services Canada, various years).

(and key industries such as aluminum reduction and pulp and paper manufacturing) was the major force behind the early expansion of generating capacity, supplemented later by the residential and commercial sectors, which are now almost as important as industry as a source of electricity demand.

Demand and supply have interacted in a complex and dynamic fashion--at some times new breakthroughs in supply technology sparked dramatic changes in the nature of electricity demand, while at other times demand growth inspired important supply developments. We have seen that the growth of public ownership and regulation has been the dominant development in the structure of the electricity industry in Canada; this growth was the result of a complicated conjuncture of motivations, including most importantly a desire to use the vast economic strength of the industry for the purposes of industrial development and economic diversification. Finally, we have reviewed the changing nature of electricity trade in Canada--from the earliest years, when the U.S. market provided the raison d'etre for hydroelectricity developments, to the dramatic expansion of interruptible sales to the United States in the 1980s. A pressure for significant structural change is once again being felt in relation to all of these factors--supply, demand, regulation and trade--and their resolution will determine the future course of the electricity industry in Canada.

Footnotes

[1] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), pp. 105-106.

[2] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 105.

[3] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940 (Cambridge, Massachusetts: Harvard University Press, 1957), pp. 50-66.

[4] John T. Miller, Jr., Foreign Trade in Gas and Electricity in North America: A Legal and Historical Study (New York, N.Y.: Praeger, 1970), p. 10.

[5] Aidan R. Vining, "Provincial Hydro Utilities," in Allan Tupper and G. Bruce Doern, eds., Public Corporations and Public Policy in Canada (Montreal, Quebec: Institute for Research on Public Policy, 1981), p. 155.

[6] H. V. Nelles, The Politics of Development: Forests, Mines and Hydroelectric Power in Ontario, 1849-1941 (Toronto, Ontario: Macmillan, 1974), pp. 227-228.

[7] Aidan R. Vining, "Provincial Hydro Utilities," p. 156.

[8] Manitoba Hydro, A History of Hydro-Electric Power in Manitoba (Winnipeg, Manitoba: Manitoba Hydro, 1984), p. 7; R. H. Choate & F. T. Gale, "The Electric Utilities of Alberta," in The 1972 Proceedings of the Canadian Electrical Association, p. 128.

[9] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940, p. 97.

[10] Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930 (Philadelphia, PA: Temple University Press, 1986), p. 94.

[11] For a chronology of the historical development of electricity supply in Canada, see Table A.3 of Appendix A.

[12] Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, p. 192.

[13] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940, pp. 68, 97.

[14] L. A. Bateman, "The Manitoba Utility Story--Day 1 to Year 1974," in The 1974 Proceedings of the Canadian Electrical Association (Montreal, Quebec: CEA, 1974), p. 130.

[15] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940, p. 25.

[16] A. J. O'Connor, "The New Brunswick Utility Story," in The 1973 Proceedings of the Canadian Electrical Association (Montreal, Quebec: Canadian Electrical Association, 1973), p. 114.

[17] David S. Templeton and Wallace S. Read, "The Newfoundland Story," in The 1975 Proceedings of the Canadian Electrical Association, (Montreal, Quebec: Canadian Electrical Association, 1975), p. 149.

[18] Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, p. 293.

[19] Statistics Canada, Historical Statistics of Canada, Series Q85-91 (Ottawa: Minister of Supply and Services Canada, 1985).

[20] R. A. Boyd and M. St. Jacques, "The Hydro-Quebec City," in The 1971 Proceedings of the Canadian Electrical Association, (Montreal, Quebec: Canadian Electrical Association, 1971), p. 116.

[21] Statistics Canada, Historical Statistics of Canada, 1985 and Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 29.

[22] See, for example, R. R. Keith and E. B. Campbell, "The Saskatchewan Power Story," in The 1970 Proceedings of the Canadian Electrical Association, who claim that SaskPower opted for a coal-fired thermal facility at Estevan in the 1960s over further development of the South Saskatchewan River for this reason.

[23] The first units of NB Power's 1050-MW oil-fired generating facility at Coleson Cove began operation in 1975, approximately 2 years after the first oil price stock. Construction of the facility was initiated several years earlier, however, when most analysts expected oil prices to remain low and stable. Ironically, at the time NB Power officials boasted that the facility was being constructed 10 years in advance of the provincial system's current capability, on the strength of a large firm export contract with the Maine Electric Power Co., which would purchase the surplus power until it was needed by New Brunswick (see A. J. O'Connor, 1973, p. 116.).

[24] See L. R. Haywood, Evolution of Nuclear Power in Canada (Chalk River: Atomic Energy in Canada Limited, 1967) for an interesting discussion of these early developments.

[25] See Philip Smith, Brinco: The Story of Churchill Falls (Toronto, Ontario: McClelland and Stewart, 1975), pp. vi-viii.

[26] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 58.

[27] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940, pp. 19-21.

[28] H. V. Nelles, The Politics of Development: Forests, Mines and Hydroelectric Power in Ontario, 1849-1941, pp. 256-306.

[29] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940, p. 41.

[30] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940, p. 45.

[31] David S. Templeton and Wallace S. Read, "The Newfoundland Story," in The 1975 Proceedings of the Canadian Electrical Association, p. 149.

[32] Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, p. 303.

[33] See Len Stahl, A Record of Service: The History of Western Canada's Pioneer Gas and Electric Utilities (Edmonton, Alberta: Canadian Utilities Ltd., 1987), pp. 54-57, for an interesting description of these efforts.

[34] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940, p. 45.

[35] Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, p. 194.

[36] H. V. Nelles, The Politics of Development: Forests, Mines and Hydroelectric Power in Ontario, 1849-1941, p. 362.

[37] John H. Dales, Hydroelectricity and Industrial Development, Quebec 1898-1940, p. 45.

[38] R. R. Keith and E. B. Campbell, "The Saskatchewan Power Story," in The 1970 Proceedings of the Canadian Electrical Association, p. 115.

[39] For a summary of important dates in the development of public ownership in the Canadian electricity industry, please see Table A.4, Appendix A.

[40] Edmonton Power Annual Report, 1979, p. 7.

[41] Energy Resources Conservation Board, Alberta Electric Industry Annual Statistics, 1987 (Calgary, Alberta: ERCB, 1987), p. 3.

[42] Manitoba Hydro, A History of Hydroelectric Power in Manitoba, p. 3.

[43] This was the reason for the defeat of Toronto's earliest effort to establish a municipally-owned system in 1895; see Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, p. 251.

[44] Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, pp. 190-191.

[45] Mark Perlgut, Electricity Across the Border: The U.S.-Canadian Experience (Washington, D.C: Canadian-American Committee, 1978), p. 10.

[46] H. V. Nelles, The Politics of Development: Forests, Mines and Hydroelectric Power in Ontario, 1849-1941, pp. 248-249.

[47] L. A. Bateman, "The Manitoba Utility Story--Day 1 to Year 1974," in The 1974 Proceedings of the Canadian Electrical Association, pp. 130-131.

[48] Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, pp. 301-302.

[49] The price of electricity in St. John fell by 60 percent between 1923 and 1925; see Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, p. 306.

[50] A. J. O'Connor, "The New Brunswick Utility Story," in The 1973 Proceedings of the Canadian Electrical Association, p. 114; Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, p. 302.

[51] Aidan R. Vining, "Provincial Hydro Utilities," p. 160; Marsha Gordon, ed., Government in Business (Montreal, Quebec: C.D. Howe Institute, 1981), pp. 28-29.

[52] See Philip Smith, Brinco: The Story of Churchill Falls, pp. 360-363, for a full explanation.

[53] See, for example, Len Stahl, A Record of Service: The History of Western Canada's Pioneer Gas and Electric Utilities, p. 55, 106. In fact, a referendum held on the subject of nationalizing the electricity industry in 1948 resulted in a virtual tie: 50.027 percent of the electorate opposed nationalization, with 49.973 percent in favour. It is interesting to note, furthermore, that Alberta was one of the few provinces in Canada to nationalize its telephone system.

[54] See Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, pp. 270-292, for a thorough discussion of this problem.

[55] Recall, for instance, that the founding mandate of Ontario Hydro was both to distribute electricity to municipal utilities and to regulate the activities of existing private utilities. Adam Beck was of the opinion, however, that "rate regulation was useless without ownership of the power," and his Commission opted to take the initiative in providing cheap, accessible power, rather than attempting to force the private utilities to do so (quoted in Christopher Armstrong and H. V. Nelles, Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930, p. 190).

[56] John T. Miller, Jr., Foreign Trade in Gas and Electricity in North America: A Legal and Historical Study, pp. 11-12.

[57] Energy, Mines and Resources Canada, Canada-United States Electricity Trade (Ottawa: EMR, July 1987), p. 19.

[58] H. V. Nelles, The Politics of Development: Forests, Mines and Hydroelectric Power in Ontario, 1849-1941, p. 227.

[59] John T. Miller, Jr., Foreign Trade in Gas and Electricity in North America: A Legal and Historical Study, pp. 25-26.

[60] John T. Miller, Jr., Foreign Trade in Gas and Electricity in North America: A Legal and Historical Study, pp. 31-32.

[61] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 107.

[62] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 23.

APPENDIX B

PROVINCIAL VIGNETTES

B.1 BRITISH COLUMBIA

Canada's most westerly province ranks third in Canada in terms of electricity generation and capacity. The province's vast hydroelectric resources have long formed the backbone for the development of its electricity system, which ranks with Quebec's and Manitoba's as one of the most hydraulic-dependent electricity systems in the country. Since the signing of the Columbia River Treaty in 1961, there has been close cooperation and extensive trade between B.C. Hydro and the neighbouring utilities of the northwestern United States. These links are set for a major expansion, according to new provincial government policies which aim to develop privately-financed power plants dedicated to the export market. Existing hydroelectric facilities have exploited perhaps only one-third of the total potential of B.C.'s rivers, but the development of the untamed northern rivers--located in wilderness areas of extraordinary beauty--would carry significant environmental consequences.

B.1.1 Industrial Structure

The British Columbia Hydro and Power Authority--more commonly known as B.C. Hydro--was incorporated as a Crown corporation in 1961. In a controversial move one year later, B.C. Hydro acquired the B.C. Power Corporation, which at the time was the largest investor-owned electric utility in Canada. Since that time, B.C. Hydro has gone on to purchase several other smaller utilities in the province, and today is the third largest electrical utility in Canada (after Ontario Hydro and Hydro-Quebec).

B.C. Hydro serves 1.2 million customers in a service area that contains over 90 percent of British Columbia's population. Until recently, the utility also owned a natural gas distribution system in Greater Vancouver and the Fraser Valley, a propane-air manufacturing plant, a local railway in the lower mainland region, and a research and development business. These non-electricity divisions of the company were put up for sale in 1988 as part of the B.C. government's privatization program.[1] B.C. Hydro's generating assets include seven major hydro developments, one major thermal plant (which is used only intermittently), and numerous smaller hydro and gas-turbine generators. Over 99 percent of the utility's electricity supply was provided by hydroelectric plants in fiscal 1987.[2]

About 10 percent of British Columbians reside in a segment of south-central B.C. that is served by the West Kootenay Power and Light Company (WKPL). This company was formed in 1897 to supply electric power to mining operations in the Trail and Rossland areas. It later expanded into residential and commercial service, based on electricity supplied by four hydro generating stations on the Kootenay River and supplemented by energy purchases from B.C. Hydro and Cominco Ltd. In 1987 the company was purchased by UtiliCorp United Inc. of Kansas City, Missouri. The electrical grids of B.C. Hydro and WKPL are fully integrated through five different high-voltage interconnections.

Private industrial firms are responsible for over 20 percent of all electricity generated in British Columbia--the highest proportion in Canada. The most prominent example of private industrial generation is the 900-MW hydro station at Kemano in northwest B.C., owned and operated by Alcan Aluminium. Other major industrial hydroelectric generators in the province include Cominco Ltd. and MacMillan Bloedel; in total, private producers account for approximately 2000 MW of generating capacity, most of it hydroelectric. With the exception of Cominco's sale of some 800 GW.h per year of surplus energy to WKPL, most of this industry-generated electricity is used internally by the companies which generate it and is not generally marketed to other consumers in the province. This will change dramatically in 1995, however, when B.C. Hydro is scheduled to begin purchasing 2500 GW.h per year of energy from an upcoming 520-MW expansion of Alcan's Kemano station. The sale will total $1.25 billion over 20 years.[3] B.C. Hydro has also proposed to purchase an additional 100-200 MW of power from private generators to help meet domestic demand, primarily in remote areas of the province.[4]

Both of B.C.'s electrical utilities are regulated by the B.C. Utilities Commission, which oversees the operation and expansion of generating and transmission facilities, major financial and ownership transactions, electricity rates and electricity exports. The provincial cabinet must also approve new removal permits for exports of power from British Columbia. In recent years, exports to the U.S. have accounted for up to 20 percent of all electricity generated by the two utilities.

In May 1988, the provincial government announced the establishment of a new B.C. Hydro subsidiary--the British Columbia Power Export Corporation, or POWEREX--to market electricity in the United States. This company will identify and cultivate potential U.S.

markets for B.C. power and could take responsibility for the development of new generating capacity to serve those markets. The provincial government envisions that most or all of these new export-dedicated projects will be constructed by private investors, leaving publicly-owned B.C. Hydro to focus mainly on serving domestic customers. In addition, B.C. Hydro has turned to long-term supply contracts with private electricity generators to meet demand requirements in remote load centres. For example, the utility recently called for tenders for the supply of 75-85 MW of power to the Fort Nelson region in the north-east of the province. Both the new electricity export corporation and these private suppliers will be subject to the same regulatory procedures as are the existing utilities.

B.1.2 Current Supply/Demand Balance

The nameplate generating capacity of the integrated B.C. electrical system is presently 10 400 MW (excluding private industrial generation).[5] Dependable or firm generating capacity is somewhat lower--9600 MW in 1987--primarily because of the exclusion of B.C. Hydro's 900-MW Burrard gas-fired thermal generating station. This facility has not been considered as firm capacity in recent years, in part because it lacked a secure source of natural gas supply in the winter months.[6] Compared to a peak domestic load of 6345 MW experienced in 1987,[7] this firm capacity leaves a reserve margin of almost 3300 MW, or some 52 percent (see Table B.1). Even with the exclusion of the Burrard facility, this reserve margin is probably an over-optimistic portrayal of the resource position of the B.C. utilities. Firstly, it should be noted that peak demand in B.C. jumped sharply during the severe cold snap experienced early in 1989, to an estimated 7500 MW; this reduces the effective reserve margin to something in the order of 28 percent. Secondly, as a hydraulic-based electricity system, it is easier for B.C. Hydro to meet peak power requirements (by temporarily operating generating facilities at rates that could not be supported by typical water flows) than it is to deliver sufficient energy requirements over the course of an entire year. The B.C. electrical system is therefore more energy-constrained than peak-constrained.

TABLE B.1

INTEGRATED B.C. SYSTEM[a] CAPACITY AND RESERVE, 1987

Installed Capacity	10 390 MW
Dependable Capacity[b]	9 637 MW
Peak Demand[c]	6 345 MW
Reserve Capacity	3 292 MW
Reserve Ratio	51.9%
Load Factor[d]	70.3%

SOURCES: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and B.C. Hydro, Annual Report, 1987.

[a] Includes systems of B.C. Hydro and West Kootenay Power and Light.

[b] Excludes capacity of Burrard thermal station.

[c] Based on 1986-1987 fiscal year (ending March 31, 1987).

[d] Average hourly energy sales as a share of annual peak demand.

Hydroelectric facilities provide for the vast majority of British Columbia's electricity needs (see Figure B.1). Close to 15 percent of the province's generating capacity consists of fossil-fuelled thermal plants, but this capacity is substantially underutilized relative to the hydraulic facilities. As a result, hydroelectricity accounted for some 97 percent of the 63 000 GW.h of electrical energy generated in B.C. in 1987.

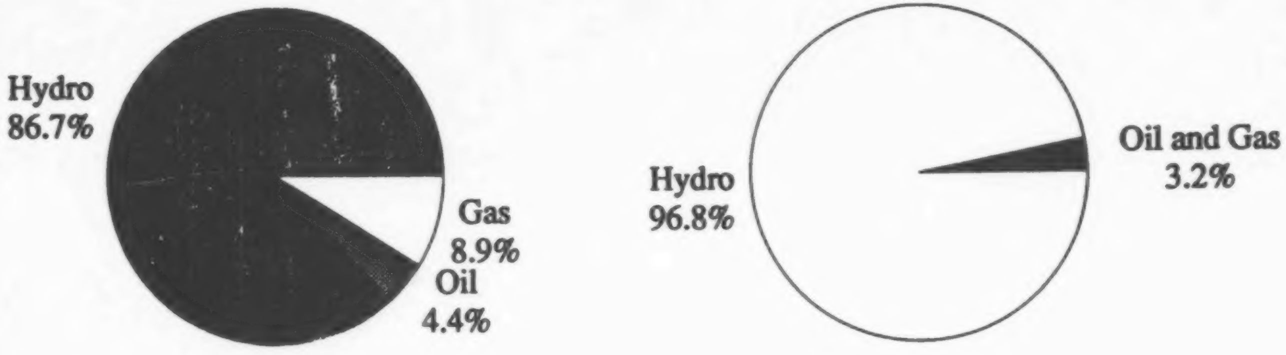
Thanks in large part to its abundant hydroelectric resources, British Columbia's economy is one of the most electricity-intensive in Canada. Per capita electricity consumption in 1987 averaged 17 356 kilowatt-hours, second in Canada behind Quebec. Total domestic consumption of 50 000 GW.h in 1987 represents about 12 percent of total Canadian electricity demand.[8] Industry accounts for a full 50 percent of electricity consumption in B.C. (see Figure B.2), with the province's large wood products industry alone consuming over 22 percent of total provincial demand.[9] The residential and commercial sectors each account for about 20 percent of provincial consumption, with another 10 percent taken up by consumption and losses within the electricity industry itself.

Domestic demand on B.C. Hydro's system has grown at an average rate exceeding 3.5 percent over the past 5 years, and by 4.7 percent in the 1986/1987 fiscal year.[10] Demand growth in the West Kootenay Power and Light service area has been somewhat slower,

Figure B.1

British Columbia Electricity Supply

1987

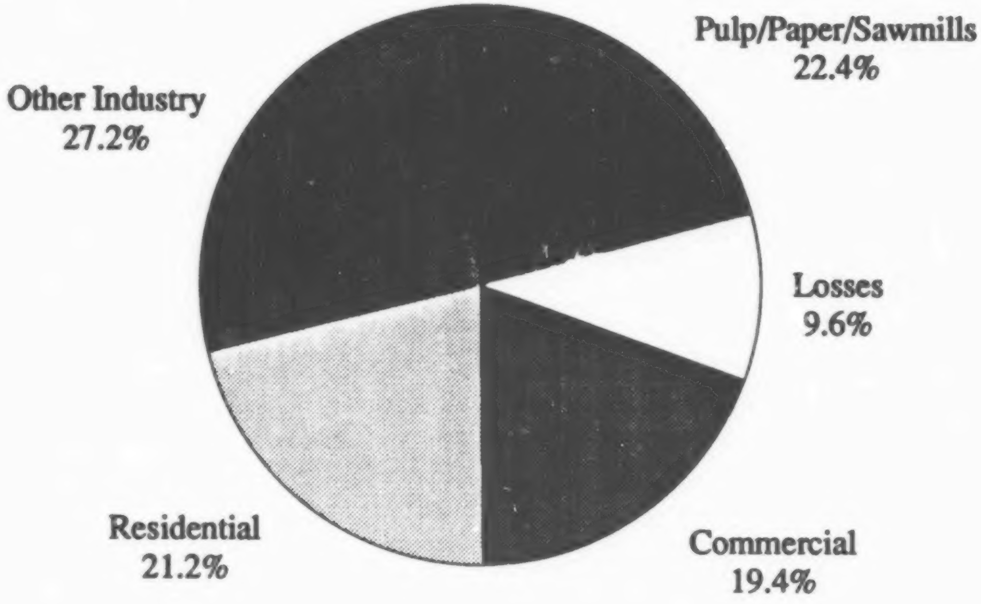


Capacity
Total: 12 508 MW

Generation
Total: 63 067 GW.h

SOURCE: EMR, Electric Power in Canada.
Note: Includes private and industrial
electricity production.

Figure B.2
British Columbia Electricity Demand
1987



Total Consumption: 51 392 GW.h

SOURCE: Statistics Canada Quarterly
Report on Energy Supply-Demand.

averaging just over 1 percent per year over the past 5 years with an annual growth rate of 3.7 percent experienced in 1987.[11] Consumption in the entire province (including consumption by those industrial firms which generate their own power) grew by 3.1 percent in 1987--slightly lower than the national average.[12]

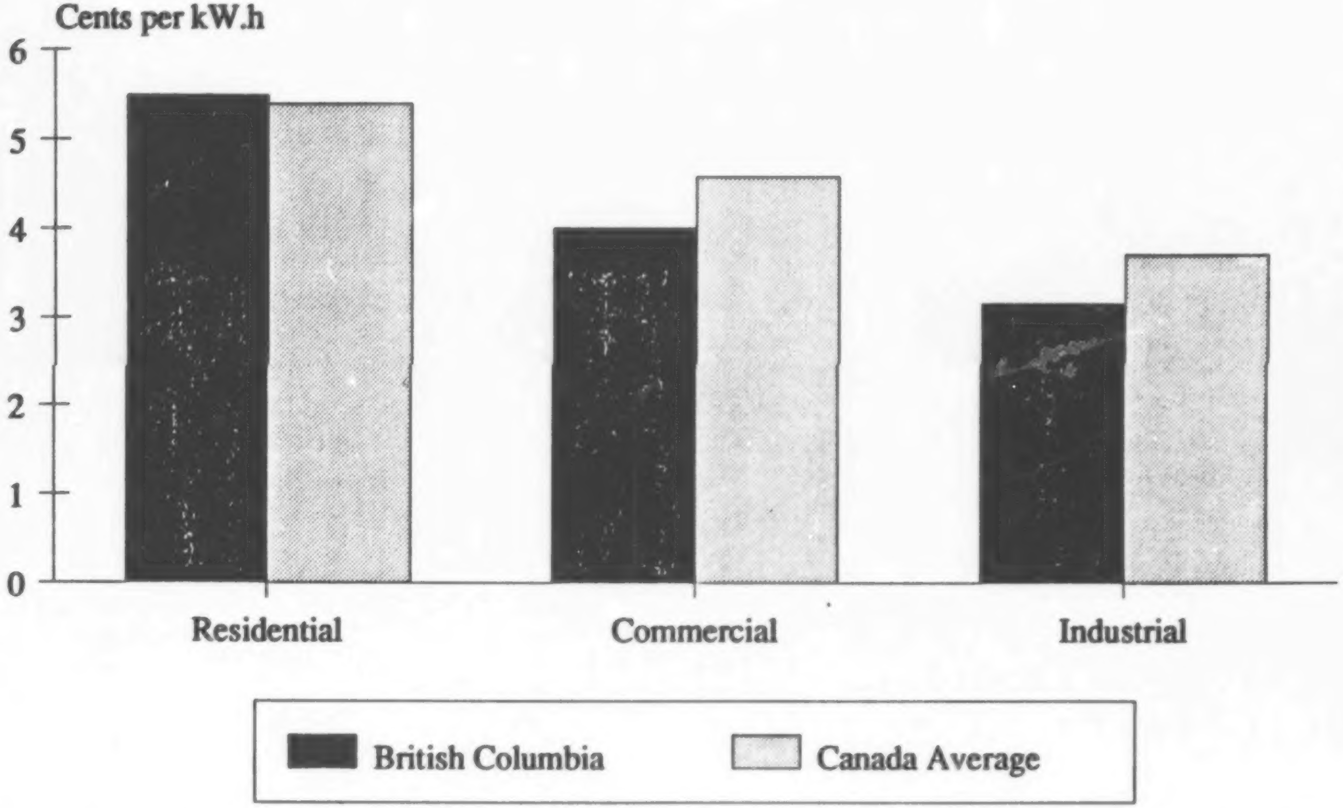
Electricity prices for residential consumers in British Columbia are slightly higher than the national average, at just less than 5.5 cents per kilowatt-hour in 1987 (see Figure B.3). This is somewhat unusual given the province's reliance on comparatively inexpensive hydroelectric resources. In part, this reflects the relatively high water rentals that the provincial government charge to electric utilities, and in part it reflects the widespread use of expensive diesel generating systems in remote areas. Industrial and commercial users, on the other hand, enjoy some of the lowest electricity rates in Canada. Industrial electricity prices may fall even further if the provincial government proceeds with a plan to reduce the water tax levied on industrial firms which generate their own hydroelectricity.[13] Electricity prices in B.C. have not kept up with inflation in recent years. Average prices charged by B.C. Hydro increased by an annual average rate of 4.5 percent between 1983 and 1986,[14] and have not been increased at all in 1987 and 1988.[15] West Kootenay Power and Light increased its rates by 4.8 percent in 1986, and by a marginal 0.1 percent in 1987.[16]

B.1.3 Electricity Trade

International electricity exports account for a large but volatile portion of total electricity generated in British Columbia (see Table B.2). Net exports to the U.S. totalled a record 12 000 GW.h in 1987,[17] making the province the second largest electricity exporter in Canada (after Quebec). This level of net exports was almost ten times the level experienced in 1986. Partly accounting for the extreme instability of B.C.'s energy exports is the fact that B.C.'s electricity exports are sold almost entirely on an interruptible basis--96 percent of the province's electricity exports in 1987 were interruptible sales.[18] Total exports therefore fluctuate tremendously as a result of changing water levels, year-to-year demand conditions in the U.S., and difficulties in securing access to necessary transmission facilities.

In particular, the Bonneville Power Administration (BPA), which controls the massive high-voltage transmission network extending from the U.S. Pacific Northwest to the energy-hungry California market, has allowed B.C. Hydro access to these lines only

Figure B.3
British Columbia Electricity Prices
1987



SOURCE: EMR, Energy Statistics Handbook.

Note: Assumes monthly bills of 1 000 kW.h residential; 300 000 kW.h commercial; 1.3 million kW.h industrial.

TABLE B.2

B.C. ELECTRICITY TRADE
1987

International Trade	
Exports:[a]	12 486 GW.h
Firm	447 GW.h
Interruptible	12 039 GW.h
California	6 021 GW.h
Oregon	4 657 GW.h
Washington	1 682 GW.h
Other	126 GW.h
Imports:	493 GW.h
Balance:	+11 993 GW.h
Interprovincial Trade[b]	
Exports:	521 GW.h
Imports:	710 GW.h
Balance:	-189 GW.h
Over-All Trade Balance	+11 804 GW.h

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a] Excludes non-marketed energy transfers.
[b] All interprovincial trade is with Alberta.

when U.S. utilities are incapable of meeting the demand themselves. B.C. Hydro has therefore been unable to obtain the secure transmission access that would be required for firm sales contracts in California and other states. Gross export revenues in 1987 totalled $206.4 million, resulting in an average export price of just 1.6 cents per kilowatt-hour--down from the average price of 2.2 cents received in 1986, and the lowest export price received by any of Canada's major exporting provinces.[19]

British Columbia is a small net importer of electricity from neighbouring Alberta on an interruptible basis--taking about 200 GW.h more than it delivered in 1987 (up from net imports of some 60 GW.h in 1986).[20] The average price paid for imports from Alberta in 1986 (the latest year for which price data is available) was 0.93 cents per kilowatt-hour, while B.C. Hydro received an average of 1.13 cents for each kilowatt-hour it sent eastward.[21]

Electricity trade between British Columbia and Alberta takes place primarily over a 500-kV high-voltage line to Cranbrook B.C., which has an installed transmission capability of 800 MW.[22] This line was constructed in 1985 to enhance reliability and coordination between the two systems. An additional 138-kV interconnection between the two provinces contributes another 110 MW of trading capacity (see Table B.3). B.C. Hydro and TransAlta Utilities are seriously considering a major expansion to these transmission links, in order to facilitate greater economy dispatch and energy sharing between the two systems. A recent Generation Coordination Study released by the two utilities suggests that joint planning of future capacity additions, together with a greater reliance on cross-border cooperation, could save a total of $1.2 billion over the next 21 years.[23] Between B.C. and the State of Washington there are two 500-kV interconnections and two 230-kV interconnections, with a total transmission capability of over 2000 MW.

TABLE B.3

INTERCONNECTION CAPACITY
BRITISH COLUMBIA, 1987[a]

Washington	2050 MW
Alberta	910 MW

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a]Includes high-voltage lines only.

B.1.4 Emerging Issues

B.C. Hydro released a 20-year resource planning document early in 1988[24] that detailed the utility's plans for future capacity expansion. But there is one dominant uncertainty--the level of exports to the U.S. in the coming years--that fundamentally complicates any effort to forecast future capacity additions in the province. B.C. Hydro's planners designed this plan such that only domestic demand growth will be adequately satisfied by predicted future capacity expansions. Any major long-term electricity sales to the U.S. would require either the acceleration of the construction schedule outlined in the B.C. Hydro plan, or the addition of entirely new, privately built facilities to the list of planned developments.

Until recently, the promise of lucrative firm power exports to the U.S. seemed virtually a certainty. B.C. enjoyed a large surplus of cheap hydroelectric power, thanks to recently completed megaprojects on the Peace and Columbia Rivers. But faster-than-expected demand growth in recent years has eaten away quickly at the reserve margin of the integrated provincial system, and transmission barriers to the sale of power in the U.S. (due in particular to the refusal of the Bonneville Power Administration to wheel B.C.'s power to the California market) have meant that exports to date have been intermittent.

B.C.'s export hopes were raised by a 1987 research report, jointly conducted by B.C. Hydro and several U.S. utilities, which concluded that a stable U.S. market exists for a 20-30 year sale of firm power from the proposed Peace River Site C facility. If this sale were to go ahead, the Site C project would have to be built 5 years earlier than required by domestic demand. Transmission access problems have at least temporarily shelved these plans, so that the latest edition of B.C. Hydro's development schedule now delays the Site C project until 2001 and plans to utilize the project's capacity solely for the B.C. market. The provincial government's planned reliance on private, dedicated generating facilities for future firm exports also makes it unlikely that the Site C project will be developed for export purposes.

Several new policy initiatives are attempting to consolidate B.C.'s long-term export opportunities. Most prominent is the provincial government's establishment of the new B.C. Hydro subsidiary, POWEREX, which was set up to market B.C. power in the U.S. This subsidiary promptly issued a call to private investors to finance the construction of export-dedicated generating plants. This might include private development of the Murphy Creek site on the Columbia River, if it were to be used to produce export power. It could also include privately-built thermal generating facilities in the eastern portion of the province (most likely utilizing waste coal from coal mines as a feedstock). Concerns regarding acid rain and other environmental problems might, however, pose a barrier to these projects.

To deliver power from these and other export plants to U.S. markets, B.C. would have to solve the problems of transmission access that have plagued the province's attempts to break into the more lucrative firm power market. As one approach to this problem, B.C. Hydro is negotiating with Washington Water Power and Puget Sound Power and Light for a firm power sale that would involve the construction of new 230-kV international transmission connections, thus bypassing the Bonneville Power Administration's system.[25] Alternatively, B.C. Hydro may use negotiations regarding the renewed sale to BPA of the Columbia River downstream benefits, scheduled to begin in 1998, as a bargaining chip in an effort to open up BPA's transmission access policy.[26]

Problems with transmission access might not be the only barrier in the way of long-term expansion of British Columbia's electricity exports. Recent studies have suggested that the province's undeveloped hydroelectric capacity rivals Quebec's as a potential basis for long-term electricity exports.[27] But some of the northern rivers targeted by B.C. Hydro for eventual development--in particular, the Stikine, Iskut, and Liard river basins, which have a combined potential hydroelectric capacity in excess of 6000 MW--are attracting increasing public attention for their natural beauty. Any effort to harness the power potential of these areas, whether for export or for domestic use, could ignite a fierce public debate regarding the environmental impact associated with their development.

TABLE B.4

INTEGRATED B.C. SYSTEM[a] MAJOR DEVELOPMENT PROJECTS

Projects	Capacity	Year in Service
Committed Projects		
Seven Mile Hydro Expansion	43 MW	1988
Oliver Gas Turbine	140 MW	1990
Alcan Kemano Expansion (firm purchase)	520 MW	1995
Columbia R. Downstream Benefits	1100 MW	1998-2003
Future Projects		
Peace River Site C Hydro	900 MW	
Keenleyside Hydro	180 MW	
Murphy Creek Hydro	275 MW	
Hat Creek Thermal Coal	up to 2000 MW	
Balmer Export Coal	600 MW	
Fording River Export Coal	110 MW	

SOURCES: (1) Energy, Mines and Resources Canada - Interfuel Substitution Demand Model; (2) B.C. Hydro; (3) West Kootenay Power and Light; (4) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (5) press reports.

[a] All projects listed in this table will feed into the B.C. Hydro system except the Oliver gas turbine generator which is a project of West Kootenay Power and Light.

If no major firm export deals are signed in the coming years, then the two B.C. utilities can meet domestic demand growth until the turn of the century without requiring the construction of any major new generating stations. The only new facility presently committed for construction is a $33 million gas turbine generating station being planned by WKPL for the Okanagan Valley (see Table B.4). In the medium-term, the balance between electricity supply and demand will be maintained by a variety of planning measures which will help to postpone the need for new facilities. These include most prominently an ambitious demand-side management program (designed to conserve 500 MW of peak demand by the year 2000), the purchase of 520 MW of power from Alcan's expanded hydro facility at Kemano (starting in 1995), and the return of 1100 MW of capacity from the downstream benefits of Columbia River hydro developments over a 6-year period starting in 1998.[28]

Despite these interim measures, however, by the turn of the century new generating projects will be required to meet expected domestic demand. At present, B.C. Hydro's plan suggests that the Site C facility will be built first (at an estimated energy cost of 3.0 cents per kilowatt-hour), followed by smaller hydro facilities at Keenleyside and Murphy Creek (estimated cost 2.9 cents per kilowatt-hour), and a huge coal-fired thermal development at Hat Creek (with costs expected to average between 3.2 and 4.1 cents per kilowatt-hour).[29] This plan will almost certainly undergo significant revisions in response to changing demand patterns before construction ultimately begins on the utility's next major electricity development.

Footnotes

[1] At time of writing, three of these subsidiaries--the rail division and the two gas companies--had been sold.

[2] B.C. Hydro, Annual Report, 1986/87, p. 2.

[3] Energy Analects, vol. 17, no. 33, August 22, 1988.

[4] Energy Analects, vol. 17, no. 24, June 20, 1988.

[5] B.C. Hydro, Twenty-Year Resource Plan, March 1988, Exhibit I-1.

[6] This may change in coming years, however, as B.C. Hydro turns to the Burrard plant to supplement its hydraulic resource base. At recent NEB hearings regarding the renewal of a B.C. Hydro electricity export license, B.C. Hydro officials reported that the utility has obtained all environmental permits necessary to operate the Burrard plant on a regular basis. This would allow B.C. Hydro to include the Burrard plant in its resource base, without which the utility would not have a sufficient energy reserve margin to export firm electricity.

[7] B.C. Hydro, Annual Report, 1986/87 (for fiscal year ending March 31, 1987).

[8] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), p. 23.

[9] Most of the remaining portion of industrial demand is attributed to the aluminum industry in British Columbia, but confidentiality restrictions prohibit the publication of this data. See Statistics Canada, Quarterly Report on Energy Supply-Demand in Canada, Catalogue No. 57-003 (Ottawa: Minister of Supply and Services Canada, various years).

[10] B.C. Hydro, Annual Report, 1986/87, p. 10.

[11] West Kootenay Power and Light Company, Annual Report, 1987, pp. 14-15.

[12] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 21.

[13] The Vancouver Sun, December 2, 1988, p. D-1.

[14] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 65.

[15] Response of B.C. Hydro to questionnaire distributed by the Electrical Energy Branch, EMR Canada.

[16] West Kootenay Power and Light, Annual Report, 1987 p. 6.

[17] Energy, Mines and Resources Canada, Electric Power in Canada: 1987.

[18] National Energy Board, Annual Report, 1987, p. 100.

[19] Ibid.

[20] Energy, Mines and Resources Canada, Electric Power in Canada: 1987.

[21] Statistics Canada, "Electric Power Statistics," Catalogue No. 57-202 (Ottawa: Minister of Supply and Services Canada, various years). These figures include power exchanges, which explains why the average prices are so low.

[22] All data on interconnection facilities is taken from Energy, Mines and Resources Canada, Electric Power in Canada: 1987, 1986 and 1985.

[23] Energy Analects, vol. 18, no. 14, April 10, 1989.

[24] B.C. Hydro, Twenty-Year Resource Plan, March 1988.

[25] Energy Analects, vol. 17, no. 29, July 25, 1988; and Energy Analects, vol. 18, no.13, April 3, 1989.

[26] Vancouver Province, April 6, 1989.

[27] See, for example, Energy, Mines and Resources Canada, Electric Power in Canada: 1987, pp. 114-115, which lists gross undeveloped hydroelectric potential in B.C. as 31, 500 MW--close to 20 percent of total Canadian potential. Similarly, U.S. Department of Energy, Northern Lights: The Economic and Practical Potential of Imported Power from Canada, by Jeffrey Skeer (Washington, D.C.: U.S. Department of Energy, December 1987), p. A-1, estimates total undeveloped hydroelectric potential in British Columbia at 24 000 MW, versus 37 500 MW in Quebec and 11 250 MW in all other provinces combined.

[28] Under the terms of the 1961 Columbia River Treaty, Canada and the U.S. agreed that the construction and coordinated operation of three new reservoirs in the Canadian portion of the Columbia watershed would increase the capacity of existing downstream hydroelectric facilities in the U.S. by some 2800 MW, and increase their energy production by 11 000 GW.h per year. The Treaty splits these benefits between the two countries, but B.C. Hydro immediately sold its share of the downstream benefits to the participating U.S. utilities for 30 years for a total payment of $254 million. These contracts will expire starting in 1998, when the U.S. utilities will be obliged to begin supplying B.C. Hydro with its share of the downstream power. B.C. Hydro is currently negotiating with the U.S.

utilities regarding the possible resale of the downstream benefits; for this sale to be beneficial for B.C., it would have to generate more revenue than would be required to develop alternate supply sources within B.C. to meet domestic demand. See Mark Perlgut, Electricity Across the Border: The U.S.-Canadian Experience (Washington, D.C.: Canadian-American Committee, 1978), pp. 10-11.

[29] B.C. Hydro, Twenty-Year Resource Plan, March 1988.

B.2 ALBERTA

The electricity industry of Alberta has bucked the historical trend experienced in the rest of Canada in at least two important ways. Firstly, public ownership has not achieved a significant foothold in the province's electricity sector. Alberta's two major electric utilities, TransAlta Utilities and Alberta Power, are the largest investor-owned suppliers of electricity in Canada, and together account for about 95 percent of all electricity generation by private utilities in the country. Only Prince Edward Island (which imports most of its electricity) has a higher proportion of private ownership in the electricity industry.

Secondly, Alberta relies less on hydroelectricity than any other province in Canada (again with the exception of P.E.I.). Alberta has an estimated 10 000 MW of identified undeveloped hydraulic generating potential[1]--more than other provinces such as Manitoba, Ontario and Newfoundland--but this potential has been ignored for the time being in favour of the utilization of domestic coal reserves. Growing concern with the problems of acid rain and the greenhouse effect may prove to be the only major wrench in the works for this coal-based development strategy. Alberta's coal is low-sulphur, and no serious acidification has yet been detected in the province's lakes. Nevertheless, the continued large-scale expansion of the province's coal-burning capacity will eventually come up against the same environmental constraints that are already being felt in other coal-reliant provinces, especially in light of accumulating evidence on the link between carbon dioxide emissions and global warming.

B.2.1 Industrial Structure

TransAlta Utilities Corp. is the largest electric utility in Alberta. Its predecessor firm, Calgary Power, began service in 1911. The generation capacity of TransAlta Utilities accounted for 70 percent of total electricity production in the province in 1987, servicing an area that includes Calgary (through a municipally-owned distribution system) and the better portion of south and central Alberta. It owns and operates three coal-fired generating stations (including the 2200 MW Sundance facility, which is the largest thermal electricity plant in Canada outside of Ontario) and 13 hydroelectric plants, most of which are located on the Bow River and its tributaries. TransAlta Utilities is the largest producer of coal in the country, supplying its coal-fired generating stations from its two mines and accounting for roughly one-quarter of all coal produced in Canada.[2] The company owns a controlling interest in four subsidiary firms involved in businesses as diverse as fly-ash sales, computer technology, clean coal combustion research and rural electrification.

The second major private utility operating in the province is Alberta Power Ltd., a subsidiary of Canadian Utilities Ltd., which in turn is controlled by Calgary-based ATCO Ltd. This company generated just under 20 percent of Alberta's electricity supply in 1987, and operates in a service area that includes most of northern Alberta and portions of the eastern region of the province. Two other subsidiaries of Canadian Utilities--the Yukon Electrical Co. and Northland Utilities Enterprises Ltd.--generate and distribute electricity in portions of the Yukon and Northwest Territories. With TransAlta Utilities, Alberta Power jointly owns the new coal-fired Sheerness generating station, which began to produce electricity in 1986; the second 380-MW generating unit at Sheerness is scheduled to be completed in 1990. Other electricity supply is provided by Alberta Power's own coal-fired and hydroelectric stations located in northern Alberta.

Edmonton Power, the largest municipally-owned electricity generator in Canada, is the third major player in Alberta's electric supply network. It was established in 1902 when the City Council purchased a small thermal generating station for $13,500. It presently owns and operates two natural gas generating stations with a combined capacity of almost 1000 MW.[3] These plants have not been utilized very intensively in recent years, with Edmonton Power preferring to purchase less expensive coal-generated electricity from Alberta Power and TransAlta Utilities. Edmonton Power is set to almost double its generating capacity, with two 400-MW, coal-fired generating units at Genesee, west of Edmonton. One unit of this plant is scheduled for completion later in 1989, with the other coming on stream in 1991.[4]

In addition to Edmonton Power, a smaller municipally-owned utility in Medicine Hat operates 160 MW of gas-fired generating capacity, supplied primarily by the city's own shallow natural gas wells. This utility accounted for about 1.5 percent of total generation in Alberta in 1987. Three cities in Alberta--Calgary, Lethbridge and Red Deer--own their own electricity distribution networks, supplied solely by power purchased from TransAlta Utilities.

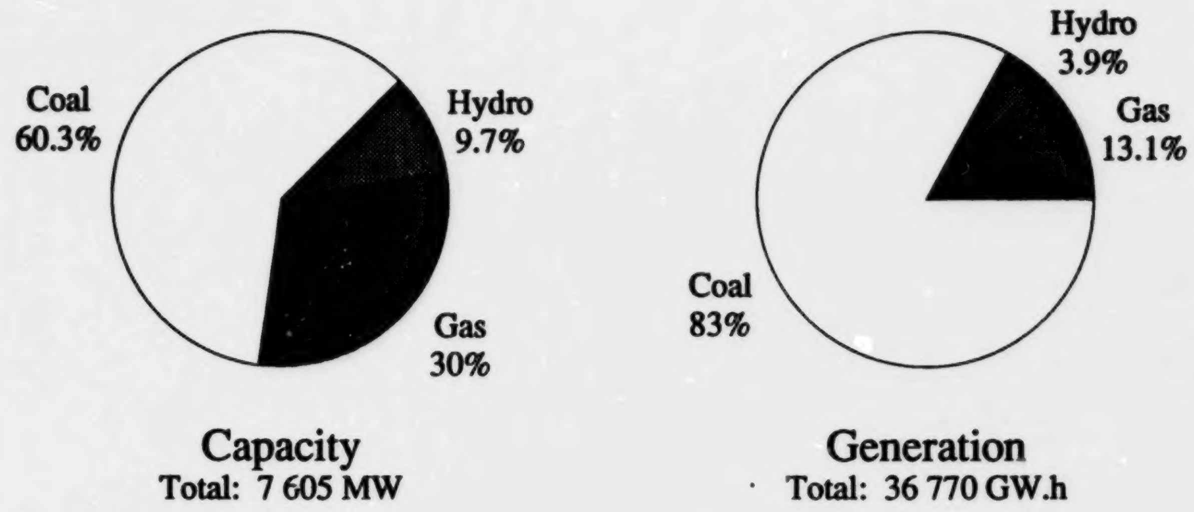
All utilities in Alberta are regulated by the Energy Resources Conservation Board (ERCB) with regard to new facilities, changes in service areas, and the environmental and social impacts of utility operations. The Board's recommendations in turn are subject to final approval by the provincial cabinet. The electricity rates of the two investor-owned utilities are directly regulated by the Public Utilities Board.[5] Additionally, TransAlta Utilities, Alberta Power, and Edmonton Power all participate in the cost-pooling program of the Electric Energy Marketing Agency, which was established in 1982 to help equalize the rates paid by consumers in different parts of the province.

On-site generating facilities operated by private industrial firms accounted for some 685 MW of capacity--close to 10 percent of the provincial total--in 1987.[6] Generation by industrial firms contributed some 3250 GW.h to provincial electricity production that year, about 9 percent of the Alberta total.

B.2.2 Current Supply/Demand Balance

The generating capacity of the interconnected Alberta electricity system totalled some 6600 MW in 1987 (see Table B.1). Province-wide peak demand reached just over 5000 MW that year, leaving about 1600 MW of reserve capacity and a reserve margin of more than 30 percent. In excess of 80 percent of the province's electricity supply was produced by coal-fired facilities in 1987 (see Figure B.1), which account for only about 60 percent of total installed generating capacity in Alberta. As a result, Alberta ranks consistently with Ontario as one of the two largest producers of coal-fired electricity in Canada.[7] The province's considerable natural gas generating capacity is significantly underutilized, with an average capacity utilization factor of less than 25 percent in 1987.

Figure B.1
Alberta Electricity Supply
1987



Capacity
Total: 7 605 MW

Generation
Total: 36 770 GW.h

SOURCE: EMR, Electric Power in Canada.
Note: Includes private and industrial electricity production.

TABLE B.1

ALBERTA INTERCONNECTED SYSTEM CAPACITY AND RESERVE, 1987

Installed Capacity	6602 MW
Peak Demand	5024 MW
Reserve Capacity	1578 MW
Reserve Ratio	31.4%
Load Factor[a]	80.2%

SOURCES: (1) Alberta Electric Industry Annual Statistics, ERCB, 1987; (2) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (3) Response of Alberta Power to questionnaire distributed by the Electrical Energy Branch of Energy, Mines and Resources Canada.

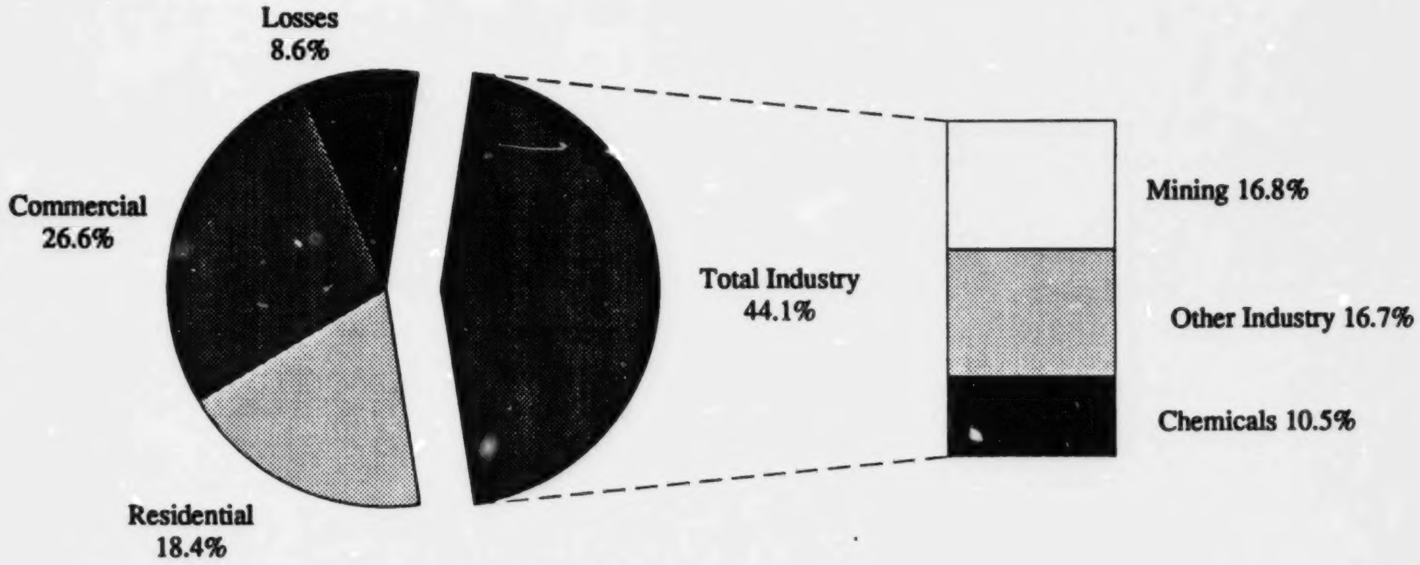
[a] Average hourly energy sales as a share of annual peak demand.

The industrial sector is the largest consumer of electricity in the province, accounting for some 44 percent of total domestic demand (see Figure B.2). Petroleum-related activity, in particular, is a major electricity user. Most of the "mining" demand identified in Figure B.2 refers to energy used by electric oil and gas well pumps, while the province's growing petrochemicals industry is also a major electricity consumer. Residential consumption in Alberta is much lower than in other provinces, primarily because of the ready availability of natural gas for space and water heating. Per capita consumption of electricity in the province averaged 15 277 kilowatt-hours per person in 1987, which is some 10 percent lower than the average for Canada as a whole.[8]

The consumption of electricity in Alberta has been growing at a rate much faster than in most other provinces in recent years, fuelled primarily by increases in industrial consumption. Domestic demand grew by 5.6 percent in 1987 (versus 3.9 percent for Canada as a whole), following a 4.1 percent increase experienced in 1986. The expectation of a boom in the province's natural gas industry and new investments in pulp and paper facilities in the northern region of the province suggest that this rapid growth in consumption will continue through the medium-term future.

Alberta enjoys relatively low electricity prices, as illustrated in Figure B.3. Average industrial rates in 1987 of 3.17 cents per

Figure B.2
Alberta Electricity Demand
1987



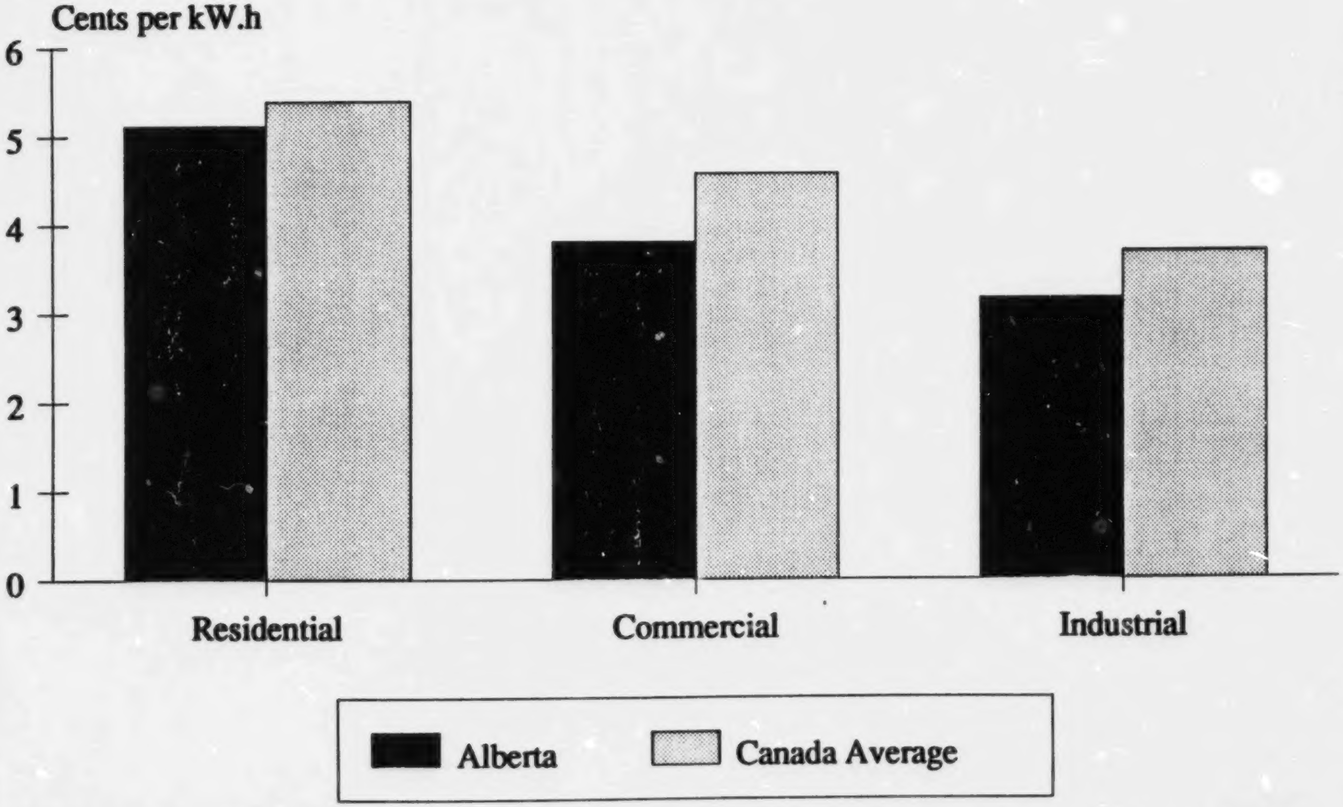
Total Consumption: 36 490 GW.h

SOURCE: Statistics Canada Quarterly Report on Energy Supply-Demand.

Note: Mining includes petroleum exploration and production.

Figure B.3

Alberta Electricity Prices
1987



SOURCE: EMR Canada, Energy Statistics Handbook.

Note: Assumes monthly bills of 1 000 kW.h residential; 300 000 kW.h commercial; 1.3 million kW.h industrial.

kilowatt-hour rank with those offered in British Columbia and Quebec as among the lowest in Canada.[9]

B.2.3 Electricity Trade

Electricity trade does not presently play a major role in Alberta's electricity system. No connection exists with the system of SaskPower, although a 100-MW transmission link is presently under construction and scheduled to be completed in 1989. Neither does Alberta trade in electricity with the United States. All of Alberta's electricity exports and imports, therefore, take place across the Alberta-B.C. border, primarily over a 500-kV transmission connection (completed in 1985) with a maximum transfer capacity of 800 MW.[10] The completion of this link has allowed TransAlta Utilities to engage in a variety of cooperative measures with B.C. Hydro--such as emergency backup, economy dispatch and exchanges of power, and joint maintenance scheduling--that have benefited both utilities. The two companies are studying a further expansion of this cooperative relationship. A recent Generation Coordination Study carried out in the two provinces promised savings of up to $1.2 billion resulting from increased cross-border trade and joint generation planning.[11] Alberta was a small net exporter of electricity to British Columbia in 1987, selling 710 GW.h to B.C. Hydro (less than 2 percent of total generation) and importing 521 GW.h.

B.2.4 Emerging Issues

Alberta's three electric utilities have committed themselves to the construction of an additional 1200 MW of coal-fired capacity within the next 3 years, consisting of 400 MW in the second generating unit of the Sheerness Station (jointly owned by TransAlta and Alberta Power) and about 800 MW in the first two units of the Genesee plant (being constructed by Edmonton Power). According to the planning strategy adopted by these utilities at the present time, meeting future demand requirements in the province will simply be a matter of adding new coal-fired units as the need arises. As many as five more 400-MW, coal-fired generating units, in addition to the three specified above, could be added to the provincial grid by the year 2000. Domestic reserves of coal are more than sufficient to meet the demand of the electricity system for the foreseeable future. Supplementary gas-fired peaking units will also be built as required. No plans currently exist for the development of further hydroelectric sites in the province, although preliminary studies were carried out earlier in the 1980s of two potential 1000+ MW sites on the Slave River in the north of the province.

In this light, it might seem that the planning process facing Alberta's utilities is a relatively straightforward one: simply build more coal-fired generators (which have shorter lead times than hydroelectric or nuclear facilities) whenever demand growth warrants them. In practice, however, the province's electricity planners face a more demanding task than this. Alberta's resource-based economy is notoriously unstable, and electricity demand can vary sharply with provincial economic conditions. This is particularly true of electricity-intensive industries, such as the growing pulp and paper sector and petrochemicals. Incorrect demand forecasting has sparked some controversy regarding the province's electricity cost-pooling system; the Public Utilities Board recently ruled, for example, that the first unit of Edmonton Power's Genesee plant could not be included in the utility's rate base (for purposes of EEMA cost-sharing) upon completion in 1989, since its power is not yet needed by the integrated provincial system.[12]

The environmental consequences of Alberta's continued reliance on coal for electricity supply is another major uncertainty facing the provincial electricity system. As mentioned in the introduction, Alberta does not yet face a major environmental problem associated with the acid emissions of its electricity plants. But a major increase in coal-fired generation to meet the province's vibrant electricity demand, combined with the sulphur emissions of Alberta's gas processing and synthetic crude oil plants, will certainly require that close attention be paid to the associated environmental consequences in the coming years. Monitoring of the acid levels in Alberta lakes is taking place on a regular basis, and TransAlta Utilities is conducting state-of-the-art research into clean-coal generation technology. Nevertheless, the concern of Albertans with the quality of their environment is increasing, and will be a major factor affecting the future development of the province's electricity system. Recent concern with the high carbon dioxide emissions associated with coal-fired generation, and the contribution of these emissions to the greenhouse effect, will further heighten environmental misgivings regarding continued reliance on a coal-based electricity system.

The ownership structure of Alberta's electricity industry is of interest to the study of various privatization or deregulation initiatives. The Electric Energy Marketing Agency is a unique experiment in attempting to provide uniform electricity prices to consumers in different service areas, while at the same time preserving the operating autonomy of the participating utilities. The province is also experimenting with the supply of electricity from smaller private power producers. Following a series of ERCB-sponsored public hearings, the provincial government in 1988 implemented a new policy designed to stimulate the small power industry. Under this policy, Alberta utilities will purchase electricity from qualifying small producers for a price of 5.2 cents (in fixed nominal terms) per kilowatt-hour--one of the more generous small power purchase rates set in Canada. The program will be in place for an initial 6-year period, covering up to 125 MW of small power capacity, at which time the government will evaluate the viability of the small power industry to determine if the program should continue.

Footnotes

[1] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), p. 113.

[2] TransAlta Utilities, Annual Report, 1987, p. 8.

[3] Energy Resources Conservation Board, Alberta Electric Industry Annual Statistics, 1987 (Calgary, Alberta: Energy Resources Conservation Board, 1988), p. 3.

[4] The commissioning date of the second Genesee unit will be reviewed by the Energy Resources Conservation Board in mid-December 1989.

[5] Edmonton Power's rates are set by Edmonton City Council; in this case, the Public Utilities Board only regulates the price at which Edmonton Power electricity is sold into the provincial electric power rate pool.

[6] Energy Resources Conservation Board, Alberta Electric Industry Annual Statistics, 1987, p. 3.

[7] Ontario produced slightly more coal-fired energy than Alberta in 1987, due to high demand in the province and poor water levels in Ontario Hydro's hydroelectricity system. In 1986, Alberta ranked first in the country in coal-fired electricity generation. See Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 29.

[8] Ibid., p. 23.

[9] Energy, Mines and Resources Canada, Energy Statistics Handbook (Ottawa, Ontario: EMR), Table 7.21.

[10] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 54. A second transmission link between Alberta and B.C. has a voltage of 139 kV and a capacity of 110 MW.

[11] Energy Analects, vol. 18, no. 14, April 10, 1989.

[12] Energy Analects, vol 18, no. 8, February 27, 1989.

B.3 SASKATCHEWAN

Electricity in Saskatchewan is neither as inexpensive nor as abundant as it is in the other provinces of Western Canada. Per capita consumption of electricity in the province is the third-lowest in Canada (next to Nova Scotia and P.E.I.), while electricity rates are the highest in the country outside of the Atlantic region. Coal-fired thermal plants provide the bulk of Saskatchewan's electricity supply, and the future development of the provincial electricity system is likely to be based on additional coal-fired units. Saskatchewan's electricity trade with other provinces and with the United States is minimal. The provincial Crown electric utility, SaskPower, has recorded a financial loss in seven of the past 8 fiscal years, prompting significant rate increases and serious consideration of far-reaching restructuring. Environmental concerns related to electricity development have gained support in the province, sparked especially by the Rafferty/Alameda dam complex (which is planned in part to provide cooling water for a new coal-fired thermal generating station) and by a recent proposal to build a privately-owned nuclear power station in the north of the province.

B.3.1 Industrial Structure

The Saskatchewan Power Corporation--more commonly known as SaskPower--is the dominant electrical utility in Saskatchewan. It was incorporated in 1950, 2 years after the CCF government of Saskatchewan had completed the purchase of the three largest private utilities then operating in the province. A former subsidiary of SaskPower, North-Sask Electric, was amalgamated into the main firm at the end of 1987. SaskPower is involved in the distribution of both electricity and natural gas, although in May 1988 the provincial government announced its intention to separate these two divisions of the company into independent Crown corporations. It is now considering the possibility of privatizing the natural gas utility. SaskPower operates 11 major generating stations: four hydroelectric plants, four coal-fired thermal stations, and three smaller natural gas units.

SaskPower has experienced a period of financial difficulty in recent years. The electrical utility component of the corporation lost a total of $145 million between 1981 and 1986, offset somewhat by profits from natural gas operations.[1] In 1986, the company decided to increase electricity rates by 7.5 percent annually for 3 years in an effort to rebuild its financial health. Subsequently, the electric utility turned its first profit in 8 years in 1987, with net income of $20 million.

SaskPower is managed by an 11-member Board of Directors, which includes a member of the provincial cabinet responsible for the corporation. The board reports to the Crown Management Board of the provincial government. Rates and other operations of the firm are subject to the ultimate approval of the provincial cabinet; the previous regulatory body, the Public Utilities Review Commission, was abolished by the provincial government in 1987. New construction projects must be approved as to their environmental impact by the Minister of Environment and Public Safety, who may require an environmental impact assessment to be completed.

B.3.2 Current Supply/Demand Balance

SaskPower's total installed generating capacity in 1987 was approximately 2750 MW, less than 3 percent of the Canadian total (see Table B.1). The utility experienced a peak load of just under 2200 MW in 1987, leaving a reserve margin of over 550 MW and a reserve ratio of 25 percent. Over 60 percent of the province's generating capacity consists of coal-fired thermal generators, which produced about 70 percent of total electricity supply in the province in 1987 (see Figure B.1). Most of the remaining energy was produced by hydroelectric facilities, with a small share generated by natural gas.

TABLE B.1

SASKATCHEWAN POWER SYSTEM CAPACITY AND RESERVE, 1987

Installed Capacity	2753 MW
Peak Demand	2195 MW
Reserve Capacity	558 MW
Reserve Ratio	25.4%
Load Factor[a]	66.9%

SOURCES: (1) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (2) Saskatchewan Power Corp., Annual Report, 1987.

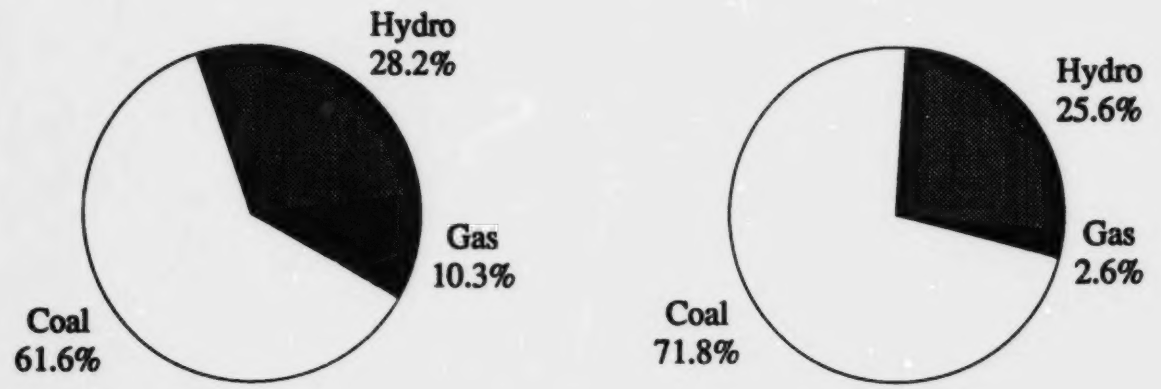
[a] Average hourly energy sales as a share of annual peak demand.

Saskatchewan is a relatively small consumer of electricity. On a per capita basis, Saskatchewan's total demand of 12 451 GW.h in 1987 works out to an average of just over 12 000 kilowatt-hours per person per year--about 70 percent of the national average, and the third-lowest in the country.[2] The industrial sector accounts for a comparatively small share of this consumption, utilizing only one-quarter of all supply in 1987 (see Figure B.2). Residential and farm use take the largest share of total provincial demand, combining to consume over 30 percent of available energy. Demand growth in the province has been comparable to other provinces in recent years. Consumption grew by 4.1 percent in 1987, following a 1 percent drop in consumption experienced in 1986. The average annual increase in demand experienced over the last decade has been slightly more than 4 percent.

Electricity prices paid by consumers in Saskatchewan are higher than the average for Canada (see Figure B.3), and considerably higher than those in the rest of Western Canada. Residential consumers in Saskatchewan paid over 6 cents per kilowatt-hour in 1987, compared to 4.6 cents in neighbouring Manitoba and slightly more than 5 cents in Alberta. Moreover, SaskPower's rates have increased faster than those of any other major utility in Canada in recent years, by an average of 7.4 percent per year between 1982 and 1987.[3] The most recent rate increases granted to the company have followed this trend, as part of a 3-year program to improve the utility's financial health.

Figure B.1

Saskatchewan Electricity Supply
1987

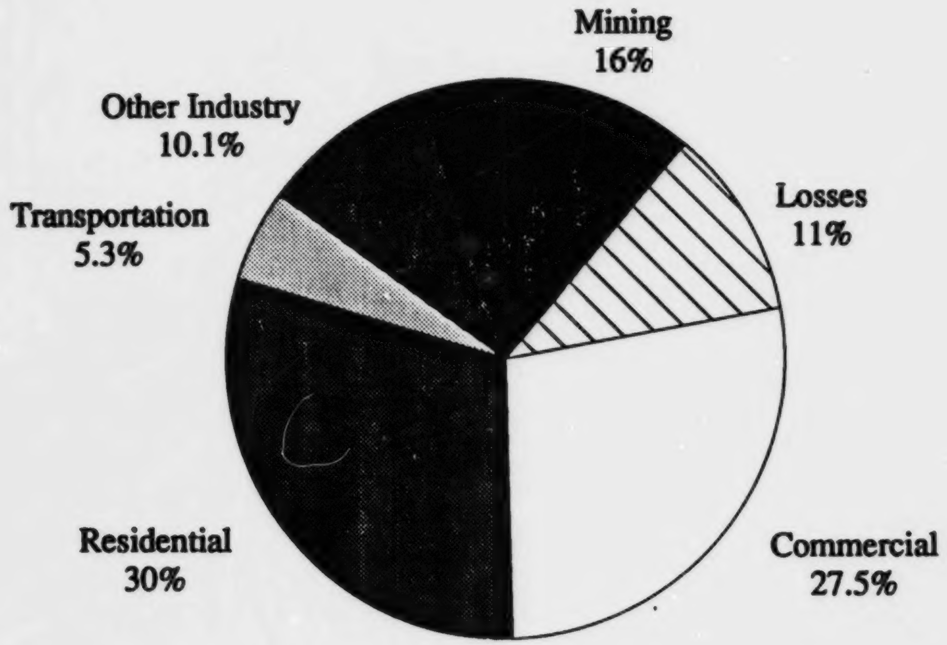


Capacity
Total: 2 948 MW

Generation
Total: 12 440 GW.h

SOURCE: EMR, Electric Power in Canada.
Note: Includes private and industrial electricity production.

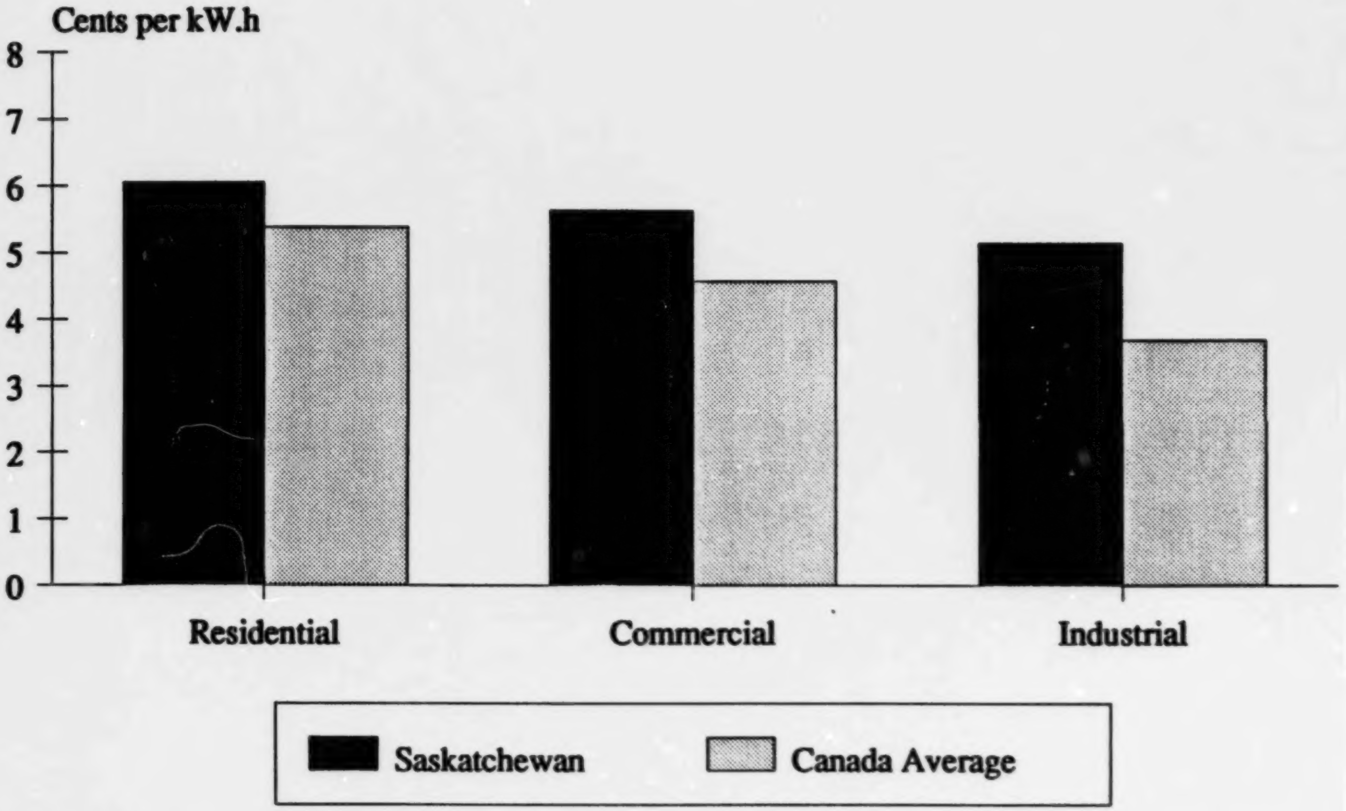
Figure B.2
Saskatchewan Electricity Demand
1987



Total Consumption: 12 474 GW.h

SOURCE: Statistics Canada Quarterly
Report on Energy Supply-Demand.

Figure B.3
Saskatchewan Electricity Prices
1987



SOURCE: EMR Canada, Energy Statistics Handbook.

Note: Assumes monthly bills of 1 000 kW.h residential; 300 000 kW.h commercial; 1.3 million industrial.

B.3.3 Electricity Trade

Saskatchewan is essentially self-sufficient in electricity, consuming only 11 GW.h more than it produced in 1987.[4] Nevertheless, relatively small amounts of electricity are traded with Manitoba and with North Dakota (see Table B.2). Transactions with Manitoba are generally exchanges of energy that take place for economy or emergency reasons, while most of SaskPower's exports to the U.S. are in the form of firm power. These U.S. sales, totalling 55 GW.h in 1987, earned a total of $168,000 at an average price of only 0.3 cents per kilowatt-hour (by far the lowest in Canada). This figure is slightly misleading, however, because Saskatchewan's firm exports--which make up 80 percent of its total exports--receive no payment at all, since they are to be returned in kind by the U.S. utilities at a later date. Saskatchewan received an average of 1.6 cents per kilowatt-hour for its interruptible exports, which is comparable to the export revenues derived by other Canadian provinces.

Saskatchewan began importing firm power from the United States in the autumn of 1988 through a 50-MW contract with North Dakota's Basin Electric Power Co-operative. The 4-year arrangement, with a total cost of $7.2 million, is intended as an interim supply measure until the province's new Shand coal-fired station is on-line in 1992.

The electrical interconnections that link Saskatchewan with other provinces are summarized in Table B.3. The single 230-kV line to North Dakota has a transmission capacity of 150 MW. Three lines of similar voltage link the electrical grids of SaskPower and Manitoba Hydro, with a combined transmission capacity of over 400 MW. An additional 230-kV interconnection with Alberta Power's system is under construction between Swift Current, Sask., and Empress, Alta. When completed in 1989, it will provide the first link between the electricity systems of Eastern and Western Canada. The 100-MW capacity of the new line is expected to allow SaskPower to postpone the construction of a limited amount of gas-fired peaking capacity, relying instead on short-term back-up power from Alberta.

TABLE B.2

SASKATCHEWAN ELECTRICITY TRADE
1987

International Trade	
Exports:[a]	55 GW.h
Firm	44 GW.h
Interruptible	11 GW.h
Imports:[b]	26 GW.h
Balance:	29 GW.h
Interprovincial Trade	
Exports:[c]	1 222 GW.h
Imports:	1 262 GW.h
Balance:	-40 GW.h
Over-All Trade Balance	-11 GW.h

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a] Excludes service exchanges.
[b] Net, including service exchanges.
[c] All interprovincial trade takes place with Manitoba.

TABLE B.3

INTERCONNECTION CAPACITY SASKATCHEWAN, 1987[a]

North Dakota	150 MW
Manitoba	400 MW

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a]Includes high-voltage lines only.

B.3.4 Emerging Issues

Until recently the future development of Saskatchewan's electricity system seemed rather predictable: a continued reliance on coal-fired thermal generating stations, which are constructed as necessary to meet consistent and moderate growth in domestic electricity consumption. But a variety of factors--including rapid domestic demand growth, the difficult financial situation of SaskPower, the conservative economic philosophies of the provincial government, and a more vocal assertion of environmental concerns--have combined to increase the degree of uncertainty surrounding the electricity industry in Saskatchewan. Recent load forecasts by SaskPower project annual average growth in provincial electricity consumption of 4.1 percent in the period leading up to 1992, and a 3.4 percent annual increase in peak demand.[5] After 1992, it is expected that both of these growth rates will slow slightly, to 2.9 and 2.6 percent, respectively. Provincial demand growth in 1987 and 1988, however, was considerably faster than predicted, increasing the pressure on SaskPower to move ahead with the expansion of its generation resources.

The first 300-MW unit of the Shand coal-fired generating complex is expected to be completed in 1992, easing the province's electricity supply crunch. Until then, the imports of 50 MW of firm power from North Dakota will provide a limited amount of breathing room for SaskPower. The second unit at Shand, originally scheduled for commission in 1995 or 1996, has been placed on hold pending the resolution of environmental concerns and the government's stated desire to pursue privately-financed generation options. Additional coal-fired stations are planned to meet the bulk of future demand growth in the province for at least the next quarter-century, supplemented by a series of natural gas peaking units, built as required.

There is a modest potential for further hydroelectric development in Saskatchewan, with an estimated total of about 2000 MW of undeveloped sites identified.[6] One of the more likely hydroelectric developments is an 85-MW expansion to the Island Falls station, which could be developed as early as 1995. Another economically attractive option could be a 300-MW extension to the Poplar River hydroelectric complex. Recently, however, SaskPower has been reluctant to commit itself to the higher capital expenses associated with hydroelectric projects, and is likely to continue to postpone such projects until its financial health has been re-established. Two other hydro developments, at Choiceland and The Forks, could contribute over 500 MW to the province's generating capacity by about 2010.

There is a possibility that Saskatchewan could turn to the nuclear power option in future years, utilizing the province's abundant domestic supply of uranium. This option is being discussed in conjunction with a stated desire by the provincial government to mobilize private capital for the future expansion of electricity supplies. The government is presently considering a proposal from Western Project Development Associates for a $750 million privately-built nuclear power facility in northern Saskatchewan, which would sell its output to SaskPower under a long-term, firm contract arrangement.

Footnotes

[1] SaskPower, Annual Report, 1987, p. 30.

[2] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), p. 23.

[3] Ibid., p. 65.

[4] Ibid., p. 23.

[5] SaskPower, "Electrical Energy Requirements: 1988-2008," June 1988.

[6] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 83.

B.4 MANITOBA

Of the three prairie provinces, only Manitoba possesses enough hydroelectric resources to supply a large share of its electricity requirements. At the turn of the century, the first hydroelectric stations on the Winnipeg and Minnedosa rivers were already being built to fuel the early industrialization of Winnipeg and surrounding towns. By the 1960s, Manitoba's engineers and planners had turned their attention northward to the mighty Nelson River, which flows from Lake Winnipeg (a natural reservoir) to the Hudson Bay, and which drains a huge watershed covering half of the combined territory of the prairie provinces. Today this single river provides for up to three-quarters of Manitoba's total electricity production.[1] The energy of the Nelson has helped make Manitoba a major electricity exporter and a world leader in the technology of long-distance transmission, and has allowed the province to offer the lowest electricity rates in Canada. Plans for future development of Manitoba's electricity system also focus on further hydroelectric development of the Nelson River.

B.4.1 Industrial Structure

In 1919, the Manitoba Power Commission was formed by the provincial government to promote rural electrification. Thirty years later, in 1949, the Manitoba government established the Manitoba Hydroelectric Board, a Crown corporation, to oversee the provision of electric power throughout Manitoba. In 1952, this new provincial agency nationalized the assets of the Winnipeg Electric Railway Company, which supplied electricity to portions of Winnipeg and other parts of Manitoba. Subsequently, in 1961, the Manitoba Power Commission and the Manitoba Hydroelectric Board were merged to form what is now known as Manitoba Hydro. Several smaller independent utilities were purchased by Manitoba Hydro in the following 12 years so that, with the exception of central Winnipeg, Manitoba Hydro's service area now encompasses the entire province.

Winnipeg itself is served by the second-largest municipally-owned electricity generating utility in Canada--Winnipeg Hydro, which was established in 1906. Since Winnipeg Hydro purchases most of its electricity from Manitoba Hydro, the provincial utility is responsible for over 95 percent of the province's total electricity production. The generation and transmission systems of the two utilities are fully integrated. Private electricity generation by industrial firms accounts for an insignificant share of total electricity production in Manitoba--about 75 GW.h, or less than 1 percent, per year.[2]

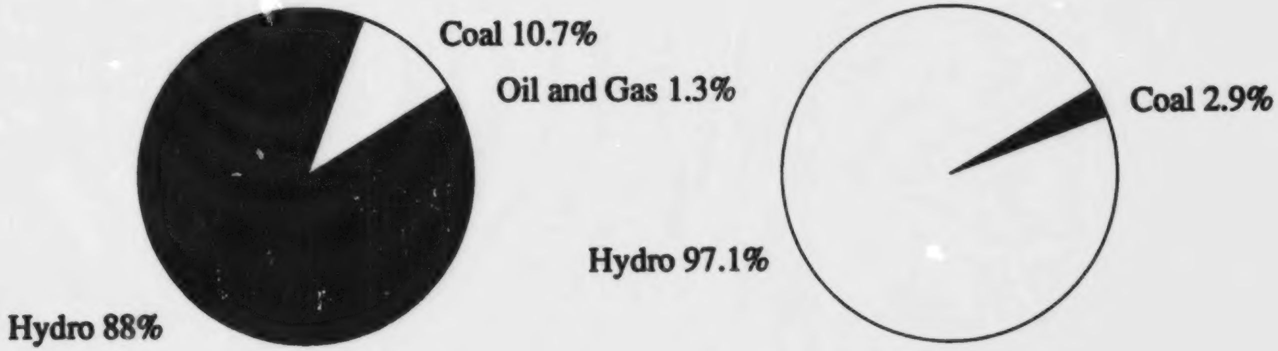
Manitoba Hydro is managed by an 11-member Board of Directors appointed by the provincial Cabinet. The corporation reports directly to the legislature through the Minister responsible for Manitoba Hydro, the Minister of Energy and Mines. Electricity rates in the province are set by Manitoba Hydro and reviewed by the Public Utilities Board; the provincial Cabinet has final authority over prices and other supply issues. Electricity exports from Manitoba--whether to the United States or to other provinces--are the separate responsibility of the Manitoba Energy Authority, whose directors are also appointed by the provincial government. In practice, the Authority serves as the extra-provincial marketing wing of Manitoba Hydro, initiating sales negotiations and arranging contracts.

B.4.2 Current Supply/Demand Balance

Almost all of Manitoba's electricity production--up to 99 percent, depending on water levels--is supplied by hydro plants (see Figure B.1). Manitoba is thus more dependent on hydroelectricity than any other province in Canada, including Quebec. Manitoba's four largest generating stations, which together are responsible for about three-quarters of total supply, are located on the Nelson River in the north-east of the province. The Nelson River will also power Manitoba Hydro's huge new Limestone generating station, which will increase the province's generating capacity by 1280 MW, or over 30 percent, when it is completed in 1992. Slightly over 10 percent of Manitoba's generating capacity consists of coal-fired thermal plants, but these are usually utilized only for back-up purposes, or during years when poor water levels result in inadequate hydroelectricity production.

Generating capacity in the integrated Manitoba electric system (including Winnipeg Hydro's system) totalled slightly more than 4000 MW in 1987.[3] Provincial firm peak demand reached 3011 MW in 1987, an increase of 1.3 percent over 1986.[4] This leaves approximately 1000 MW of reserve capacity, for a reserve ratio of just over 35 percent (see Table B.1).[5] Electricity generation in the province totalled just under 20 000 GW.h in 1987,[6] about 20 percent of which was exported to the U.S. Exports and total generation both fell by some 4000 GW.h in 1987 from the record levels reached in 1986, due to drought conditions which seriously reduced water flows in Manitoba's major rivers.

Figure B.1
Manitoba Electricity Supply
1987



Capacity
Total: 4 137 MW

Generation
Total: 19 902 GW.h

SOURCE: EMR, Electric Power in Canada.
Note: Includes private and industrial electricity production.

TABLE B.1

INTEGRATED MANITOBA SYSTEM CAPACITY AND RESERVE, 1987

Available Capacity	4084 MW
Peak Demand	3011 MW
Reserve Capacity	1073 MW
Reserve Ratio	35.6%
Load Factor	60.5%

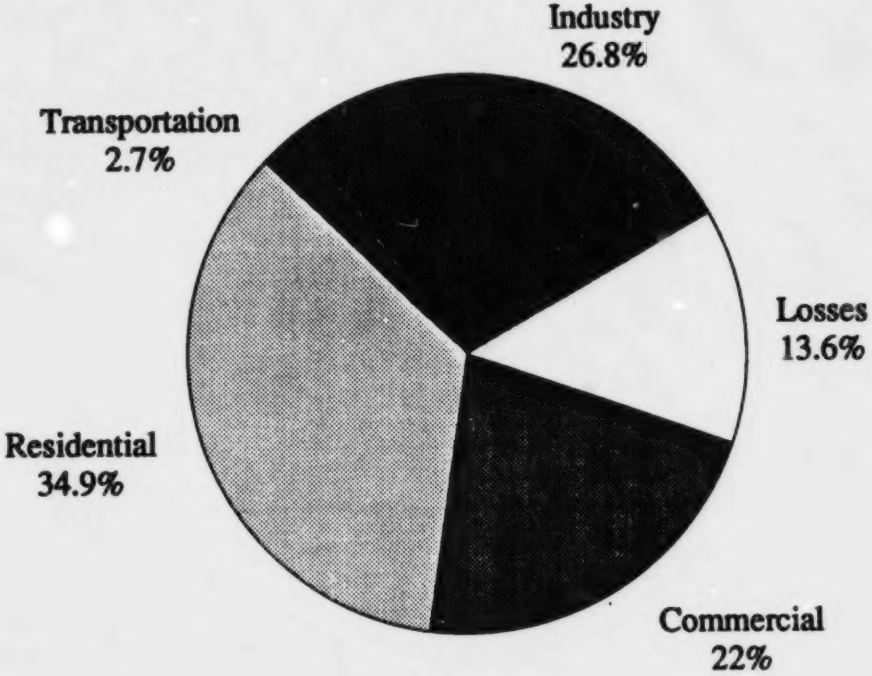
SOURCES: (1) Manitoba Hydro annual reports and submissions to Energy, Mines and Resources Canada Electricity Branch; and (2) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

Despite the abundance of hydroelectric power that the province enjoys, Manitoba is a relatively small consumer of electricity. Per capita consumption of power in Manitoba in 1987 averaged 14 649 kilowatt-hours per person--sixth in Canada, and some 15 percent below the average for Canada as a whole.[7] A relative dearth of electricity-intensive industries (such as aluminum or pulp and paper) partly accounts for this relatively low rate of consumption, as does the ready availability of alternative fuels (especially natural gas) for such uses as space and water heating. Industry consumes a smaller share of total electricity consumption in Manitoba than in most provinces, accounting for just over one-quarter of total demand, compared to over 40 percent for Canada as a whole (see Figure B.2). The bulk of the remaining consumption is divided between the residential and commercial sectors.

Electricity consumption in Manitoba grew at an average annual rate exceeding 4 percent between 1983 and 1988.[8] Domestic demand was stagnant during 1987, due primarily to abnormally warm weather, but consumption during 1988 is expected to increase by between 5 and 7 percent. Peak demand in the province has grown by an average of almost 6 percent per year since 1983--almost 1.5 times as fast as energy demand growth.

All sectors of the Manitoba economy enjoyed the lowest electricity rates in Canada in 1987, ranging from 2.77 cents per kilowatt-hour for industrial users to 4.61 cents per kilowatt-hour for residential consumers (see Figure B.3). Domestic electricity prices have increased relatively rapidly in recent years, however. An average rate increase of 9.7 percent was implemented by Manitoba Hydro in

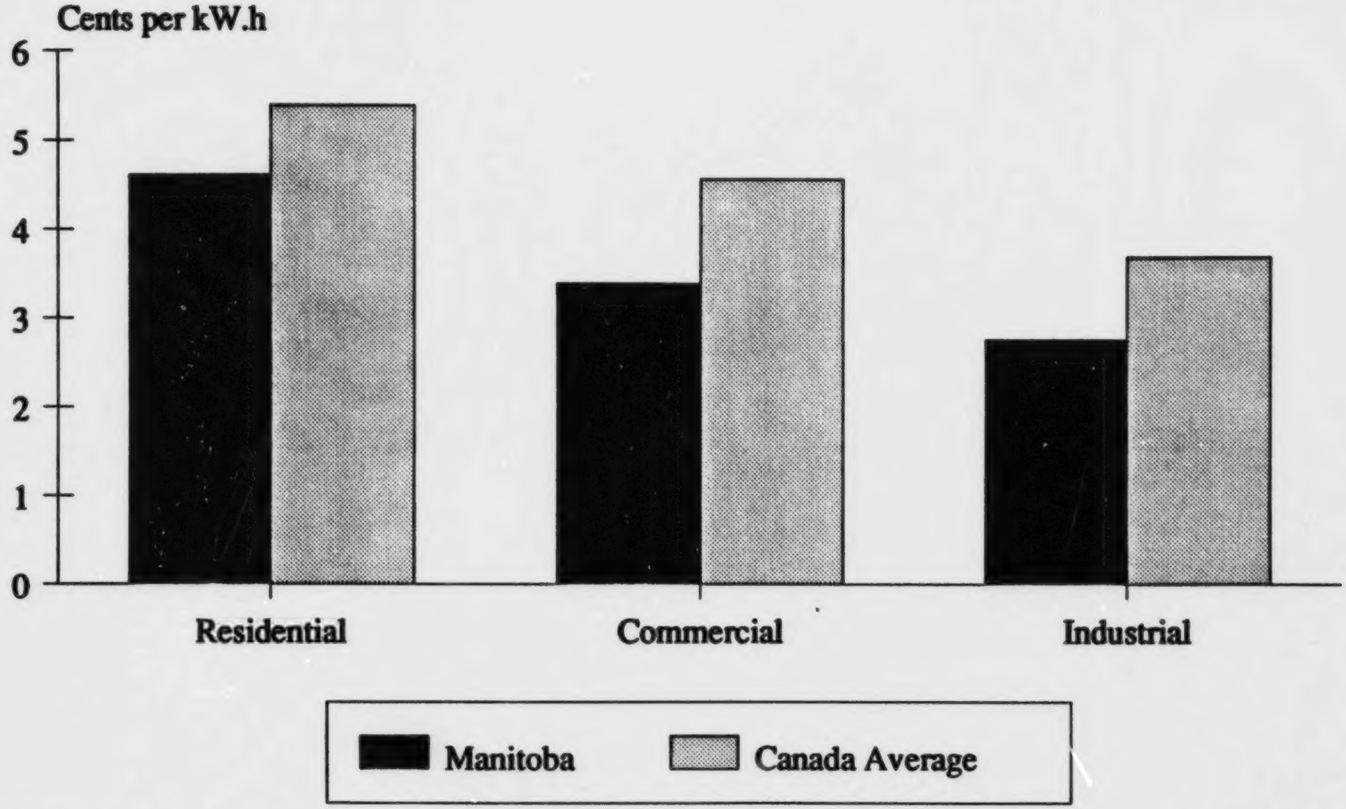
Figure B.2
Manitoba Electricity Demand
1987



Total Consumption: 15 856 GW.h

SOURCE: Statistics Canada Quarterly
Report on Energy Supply-Demand.

Figure B.3
Manitoba Electricity Prices
1987



SOURCE: EMR Canada, Energy Statistics Handbook.

Note: Assumes monthly bills of 1 000 kW.h residential; 300 000 kW.h commercial; 1.3 million industrial.

1987, with a further jump of 4.5 percent in 1988 and an increase of 6 percent requested for 1989.[9]

B.4.3 Electricity Trade

When favourable water conditions prevail, Manitoba has the capability to be a major exporter of electricity (see Table B.2). During 1986, a record 8000 GW.h of energy was exported from the province, almost one-third of total generation, making Manitoba the second-largest exporting province in Canada. Close to 90 percent of this electricity--about 7000 GW.h--was sold to the United States on a primarily interruptible basis, in return for gross revenues of some $110 million.[10] Due to poor water conditions, however, these exports fell by more than 50 percent in 1987 to a total of 3300 GW.h, with revenues of roughly $65 million. A further 147 GW.h of energy was traded with U.S. utilities in 1987 on an exchange basis. The Northern States Power Company of Minneapolis is the largest single recipient of Manitoba's power exports, with smaller quantities sold to North Dakota. Manitoba's export sales to the U.S. netted an average price of 1.97 cents per kilowatt-hour in 1987 (2.69 cents for firm sales and 1.84 cents for interruptible). This was up from an average of 1.59 cents per kilowatt-hour in 1986, but this increase was due to a greater than proportional fall in less costly interruptible exports, and was not the result of higher prices being paid by U.S. purchasers.

On the strength of the soon-to-be-completed Limestone generating station on the Nelson River, Manitoba has been aggressively marketing firm power exports to the United States. One contract with Northern States Power for the supply of 500 MW of firm power from Limestone from 1993 to 2005 has already been signed and approved by the National Energy Board. Another contract with Northern States Power provides for the provision of 200 MW of firm power during the summer months, an off-peak season for Manitoba Hydro. The prospects for further firm power sales to the U.S. are much less certain, however. Negotiations with the Upper Mississippi Power Group, a coalition of U.S. utilities, have broken down over issues of transmission costs and an appropriate pricing formula; Manitoba argues that the most recent offer of the U.S. group was not sufficiently high to justify the expenses of further Nelson River developments. Negotiations are reportedly continuing with American utilities on a one-to-one basis.

In addition to its international sales, Manitoba also sells smaller quantities of electricity to its neighbouring provinces. Net

TABLE B.2

MANITOBA ELECTRICITY TRADE
1987

International Trade	
Exports:[a]	3314 GW.h
Firm	501 GW.h
Interruptible	2813 GW.h
Minnesota	2564 GW.h
North Dakota	753 GW.h
Imports:	512 GW.h
Balance:	2802 GW.h
Interprovincial Trade	
Exports:	2311 GW.h
Ontario	1050 GW.h
Saskatchewan	1262 GW.h
Imports:[b]	1223 GW.h
Balance:	1088 GW.h
Over-All Trade Balance	+3890 GW.h

SOURCES: (1) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (2) National Energy Board, Annual Report, 1987.

[a] Excludes non-marketed energy transfers.

[b] All but 3 GW.h were received from Saskatchewan; the remainder was received from Ontario.

sales to Ontario totalled 730 GW.h in 1986, while a net total of 135 GW.h was sold to Saskatchewan.[11] Revenue from these interprovincial exports averaged 1.23 cents per kilowatt-hour in 1986.[12] Manitoba recently concluded an agreement with Ontario Hydro to provide 200 MW of firm power to Ontario between 1998 and 2003, up to a total quantity of 5600 GW.h of energy.[13] Additional firm sales to Manitoba's energy-hungry eastern neighbour are also under discussion, and Ontario could replace U.S. customers as a more important export stimulus for the future development of the Nelson River.

Manitoba's power connections with other provinces and with the United States are summarized in Table B.3. The total capacity of transmission lines to the U.S. is about 1300 MW, including a 500-kV high voltage line to Minnesota that is capable of carrying over 1000 MW of power. A total of five 230-kV lines link Manitoba with Ontario and Saskatchewan, while an additional 115-kV connection with Ontario was rebuilt in 1987.

TABLE B.3

INTERCONNECTION CAPACITY
MANITOBA, 1987[a]

Minnesota	1175 MW
North Dakota	150 MW
Saskatchewan	400 MW
Ontario	260 MW

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a] Includes high-voltage lines only.

B.4.4 Emerging Issues

The hydroelectric potential of Manitoba's northern rivers is enormous and the future development of this potential is the dominant issue facing the provincial electricity industry. Estimates of the total undeveloped hydro potential of the province range as high as 8000 MW.[14] This is in addition to the 1280-MW capacity of the Limestone plant on the Nelson River. The first of Limestone's 10 generating units is expected to be connected to the provincial electricity grid in 1990, with full completion of the $1.6 billion plant scheduled for 1992 (see Table B.4).

Until recently, it had appeared certain that firm export sales to U.S. markets would provide the stimulus for further northern developments in Manitoba. Negotiations for a firm 400- to 500-MW power sale to the U.S. Upper Mississippi Power Group from the proposed Conawapa station (a $5 billion, 1300-MW development on the Nelson River) had appeared close to a favourable conclusion. These negotiations ultimately failed in the autumn of 1988, however, over the issue of how to allocate the costs of transmission to the distant U.S. markets. Furthermore, the traditional price formula for Manitoba's firm power exports has been partly based on the cost to U.S. utilities of alternative energy sources--primarily coal, but also other fossil fuels. These costs have fallen dramatically in recent years, making it less attractive for the U.S. utilities to import firm Canadian power.

With the huge Limestone station nearing completion, Manitoba's own relatively modest domestic electricity demand could not justify the construction of another Nelson River megaproject, so the Conawapa development has been delayed indefinitely. Manitoba Hydro's planners are now examining the possibility of smaller hydroelectric developments (such as the 350-MW Wuskwatim station on the Burntwood River near Thompson) or the refurbishing of coal-fired plants at Selkirk and Brandon, as less expensive means of meeting the growth of domestic demand through the 1990s and early into the twenty-first century.[15]

As Manitoba's northern hydroelectric resources are not likely to be used for further firm export sales in the near future, Manitoba Hydro is also attempting to build its domestic load through the location of electricity-intensive industries in the province. The utility would like to attract the same types of industries--such as aluminum reduction, pulp and paper production, and chemicals--that have long used the inexpensive hydroelectric power of provinces such as Quebec and British Columbia. To this end, the province is negotiating a 20-year electricity supply contract--at very low rates--with the Dow Corning Corp., which is considering the establishment of a silicon metal operation in Manitoba. The Manitoba government had also explored the possibility of subsidized electricity supply to Alumax Inc., which was considering a variety of possible locations (including Quebec and British Columbia) for a major new aluminum plant.[16] This strategy of using inexpensive power to attract electricity-intensive

TABLE B.4

MANITOBA HYDRO
MAJOR DEVELOPMENT PROJECTS

Projects	Capacity	Year in Service
Committed Projects		
Limestone 1-2	256 MW	1990
Limestone 3-7	640 MW	1991
Limestone 8-10	384 MW	1992
Future Projects		
Conawapa	1300 MW	
Wuskwatim	350 MW	
Gillam Island	1000 MW	
Birthday	550 MW	
Gull	500 MW	
Whitemud & Red Rock	500 MW	

SOURCES: (1) Energy, Mines and Resources Canada - Interfuel Substitution Demand Model; (2) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); (3) Manitoba Hydro, Annual Report, 1988; and (4) press clippings.

industry to the province may be an alternative method of financing further development of the province's hydraulic potential.

Even with the uncertainty surrounding future exports and industrial demand, Manitoba is in a relatively enviable situation among Canadian provinces, as far as the electricity industry is concerned. Domestic rates are low, supplies from existing developments will be adequate to meet demand for years to come, and the hydraulic-based system does not face the same environmental problems as the fossil-fuel or nuclear facilities of other provinces. Although it is increasingly recognized that hydroelectric projects carry major environmental consequences of their own; for example, there have been significant social and environmental damages resulting from the widespread flooding of northern areas that followed Nelson River developments. The challenge facing the province's electricity planners is now one of utilizing Manitoba's abundant energy potential in the most effective and profitable manner.

Footnotes

[1] Manitoba Hydro, Annual Report, 1988, p. 13.

[2] Statistics Canada, Electric Power Statistics, Catalogue No. 57-202, Vol. II (Ottawa, Ontario: Minister of Supply and Services Canada, various years).

[3] The Manitoba Hydro Annual Report lists installed winter capability of 4063 MW for the integrated system in 1987, down from 4088 in 1986.

[4] Manitoba Hydro response to questionnaire distributed by the Electric Energy Branch of EMR Canada.

[5] Manitoba Hydro's estimate of the reserve ratio for fiscal 1987-1988 (ending March 31,1988) is much lower--only 21.1 percent. This reflects the sharp increase in peak demand experienced during early 1988. It should also be noted that, as a hydraulic-dependent system, Manitoba's electricity network is constrained more by energy requirements than it is by peak load. Hydroelectric facilities can be operated for short periods of time at peak capacities which cannot be sustained by normal water resources. A high peak reserve ratio is thus no guarantee that a hydroelectric system is also able to meet year-round energy demands on the system.

[6] In its response to the questionnaire distributed by the Electric Energy Branch of EMR Canada, Manitoba Hydro reports total provincial generation of 19 392 GW.h for the calendar year 1987.

[7] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), p. 23.

[8] Manitoba Hydro, Annual Report, 1988, p. 40.

[9] Manitoba Hydro response to questionnaire distributed by the Electrical Energy Branch of EMR Canada; and The Winnipeg Free Press, November 30, 1988, p. 5.

[10] All data on electricity sales to the U.S. are taken from the annual reports of the National Energy Board.

[11] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 49.

[12] Statistics Canada, Electric Power Statistics, various years.

[13] Energy Analects, vol. 16, no. 41, October 19, 1987.

[14] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 111.

[15] See "Conawapa Alternatives Considered," Winnipeg Free Press, October 12, 1988.

[16] See Winnipeg Free Press, November 9, 1988, p. 3, and December 7, 1988, p. 10. The firm eventually chose Quebec as the location for its new plant.

B.5 ONTARIO

Ontario is Canada's most populous and industrialized province, but ranks second in the country (behind Quebec) in the generation and consumption of electricity. Ontario has played a pioneering role in the development of electricity in Canada, both in a technological sense (it was the first province to develop commercial nuclear power in Canada, for example, and is still far and away Canada's largest nuclear energy producer) and in terms of organizational structure (the establishment of the Ontario Hydroelectric Commission in 1906 marked the first Canadian move towards widespread public ownership of the electricity industry). Today, Ontario's electricity system is caught in a quandary between the energy requirements of the province's booming economy on one side, and an increasingly predominant public concern with environmental protection on the other.

B.5.1 Industrial Structure

Ontario Hydro is responsible for almost all of the marketed electricity supply in Ontario. The Crown corporation was constituted in 1906 following a long and boisterous campaign by "public power" advocates, who feared that the benefits of Ontario's hydroelectric power would be largely appropriated by U.S. investors and a cartel of Toronto utilities, rather than being used to promote industrial development. At first, Ontario Hydro limited its activities to the purchase of bulk power from private generating firms and the subsequent resale of that power to municipal electricity distribution utilities. Later, the company began to construct or purchase its own generating facilities. Ontario Hydro presently has total assets in excess of $32 billion,[1] and ranks in terms of assets as the largest non-financial corporation of any kind in Canada.

The relationship between Ontario Hydro and local electricity distributors is largely unchanged from the early years of the corporation's existence. The utility generates power from its 80 separate hydraulic, nuclear and fossil-fuelled generating stations. It also purchases bulk power from neighbouring provinces (accounting for 5.2 percent of total provincial consumption in 1987),[2] as well as small amounts of power from private industrial power producers in Ontario and from U.S. utilities. Ontario Hydro wholesales this electricity to some 320 municipal utilities, which are responsible for local distribution facilities and operations. About 100 large industrial electricity users are served directly by Ontario Hydro, as are over 800,000 customers in rural areas of Ontario not serviced by a municipal utility.

A small share of generating capacity in Ontario--some 1200 MW, or about 4 percent--is privately owned. Most of this private capacity is held by industrial firms and is intended primarily to generate electricity for their own use, although there are still a small number of private regional utilities, such as Great Lakes Power which serves some 10,000 retail customers in northern Ontario. Several private power producers have arranged to sell surplus electricity to Ontario Hydro, but this parallel generation was responsible for only 26 MW of firm capacity in 1987.[3]

Ontario Hydro sets its own rates without requiring approval from any regulatory agency. Rate changes, supply planning and other matters are examined in public hearings by the Ontario Energy Board, but the corporation is free to accept or reject the Board's recommendations. This arrangement reflects the dual nature of Ontario Hydro's founding mandate in 1906, which was to not only become actively involved in the supply of electricity, but also to monitor and regulate the activities of other utilities operating in the province. Now that Ontario Hydro has evolved into the dominant utility in the province, it has become in effect its own regulator. Ontario Hydro must also approve the rates charged to final customers by its affiliated municipal utilities. Ontario Hydro is managed by a Board of Directors composed of up to 17 members, appointed by the provincial government. Construction projects initiated by Ontario Hydro (and any other utility) are subject to regulation by the provincial Joint Hearing Board, which is composed of various commissioners responsible for monitoring environmental impact and protecting municipal interests.

B.5.2 Current Supply/Demand Balance

In 1987 Ontario Hydro possessed total installed generating capacity of just over 30 000 MW (see Table B.1). Provincial firm peak demand during 1987 reached close to 21 000 MW, leaving more than 9000 MW spare capacity and a reserve margin of about 45 percent. Close to a third of this spare capacity--2667 MW in 1987--consists of non-operating reserve facilities that have been mothballed until demand conditions and other economic factors make their reactivation economically justifiable.

TABLE B.1

ONTARIO HYDRO SYSTEM CAPACITY AND RESERVE, 1987

Installed Capacity	30 080 MW
Available Capacity[a]	27 413 MW
Peak Demand	20 524 MW
Reserve Capacity[b]	9 556 MW
Reserve Ratio	46.6%
Load Factor[c]	70.5%

SOURCE: Ontario Hydro, Annual Report, 1987, pp. 46-47.

[a] Excludes non-operating reserve facilities.
[b] Includes non-operating reserve facilities.
[c] Average hourly energy sales as a share of annual peak demand.

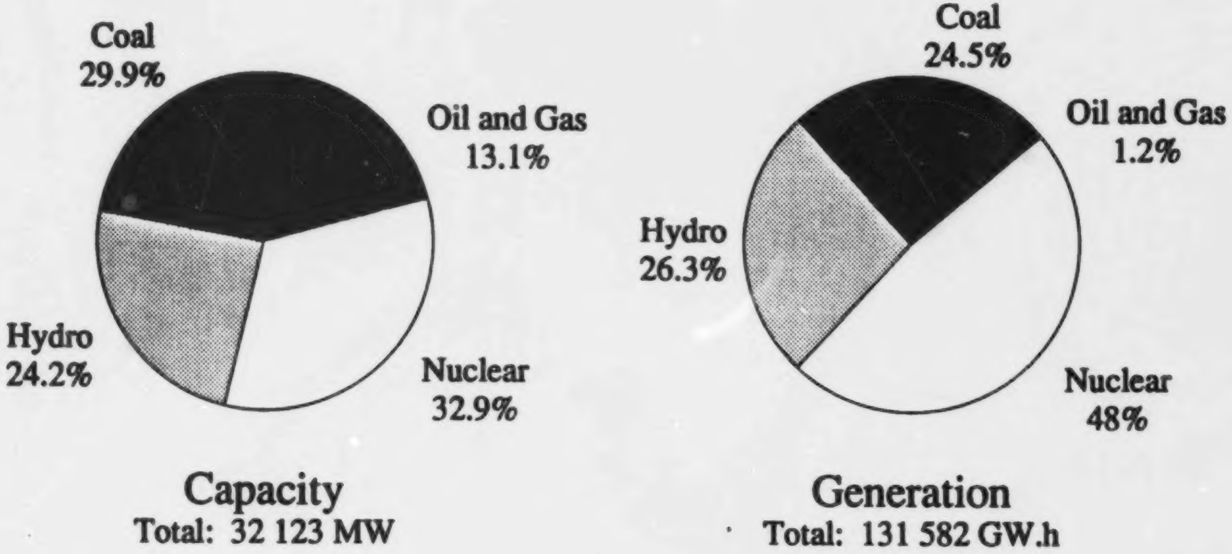
Generating capacity in Ontario is divided relatively equally amongst hydraulic, nuclear and conventional thermal fuel sources (see Figure B.1). But while accounting for less than one-third of Ontario's installed capacity, nuclear facilities were responsible for almost one-half of all electrical energy production in 1987, thanks to a higher-than-average rate of capacity utilization in the nuclear facilities.

Despite its booming and diversified economy, Ontario consumes a less-than-proportional share of Canada's electricity resources. Total electricity demand exceeded 132 000 GW.h in 1987, equivalent to per capita consumption of some 14 200 kilowatt-hours per person.[4] This rate of consumption is almost 20 percent lower than the Canadian average, and is more than 40 percent lower than per capita consumption levels in neighbouring Quebec. A sectoral breakdown of electricity demand in Ontario is provided in Figure B.2. Industry is the largest user of electricity in Ontario, accounting for a total of 35 percent of final demand in 1987. The wood products and iron and steel industries are the largest individual electricity consumers within the industrial sector, responsible for 6.2 and 4.8 percent of total provincial consumption, respectively. The residential and commercial sectors are each responsible for slightly less than one-third of total electricity demand. The remainder is consumed by the electricity industry itself ('producer consumption', which is primarily conversion and transmission losses) and by the transportation industry (electric rail and bus services, and pipelines).

Total electric energy consumption increased by about 4 percent in Ontario in 1987, a growth rate typical of recent years for the

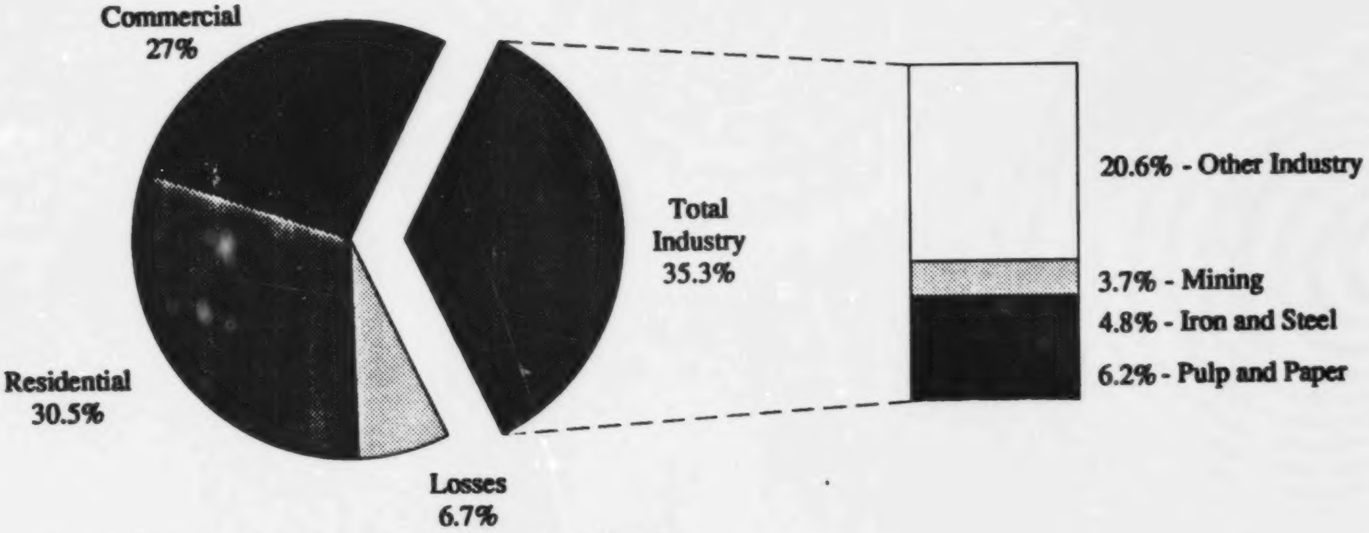
Figure B.1

Ontario Electricity Supply
1987



SOURCE: EMR, Electric Power in Canada.
Note: Includes private and industrial electricity generation.

Figure B.2
Ontario Electricity Demand
1987



Total Consumption: 132 451 GW.h

SOURCE: Statistics Canada Quarterly
Report on Energy Supply-Demand.

province and only slightly higher than the average demand increase in Canada as a whole.[5] This recent growth trend represents a departure from the experience of the late 1970s and early 1980s, when electricity demand growth was seriously hampered by high world energy prices and by economic recession. Average electricity demand growth has been the strongest in Ontario's industrial sector, with a 4.7 percent increase in 1987 and an average annual increase of 5.6 percent over the past 5 years. The iron and steel industry represents the fastest growing source of industrial electricity demand, increasing its consumption by an average of almost 10 percent per year since 1982.[6]

Electricity prices tend to be slightly higher in Ontario than is typical of other Canadian provinces (see Figure B.3), and are up to 35 percent higher than corresponding rates in neighbouring Quebec. Ontario Hydro's rates have increased roughly in tandem with inflation in recent years, with average prices rising 5.0 percent in 1987, 4.7 percent in 1988, and 5.3 percent in 1989.[7]

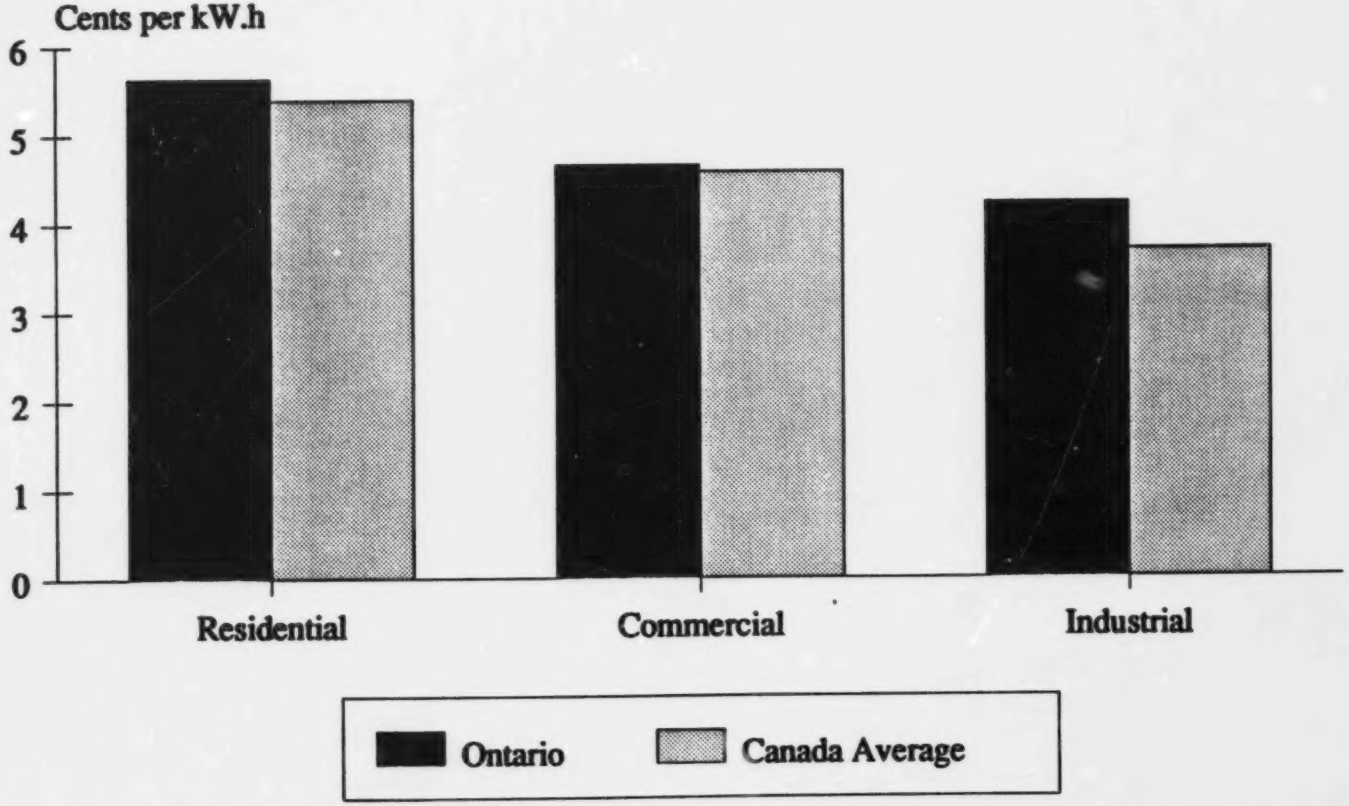
B.5.3 Electricity Trade

International and interprovincial trade accounts for a relatively small proportion of total electricity supply and demand in Ontario. As illustrated in Table B.2, Ontario sold a total of 7194 GW.h of energy to American markets in 1987, accounting for just over 5 percent of the province's total generation, and earned a total of some $215 million in export revenues.[8] Virtually all of these exports were interruptible sales, with only 265 GW.h of firm energy sold to the U.S.[9] New York State was Ontario's largest customer, accounting for over 85 percent, or about 6000 GW.h, of total exports.[10] The remaining exports were divided amongst Vermont, Michigan and Minnesota. Some 10 percent of Ontario's exports were generated by private electricity companies--primarily by the Canadian Niagara Power Company and the Cornwall Electric Company. Ontario's export sales to the U.S. netted an average price of 3.0 cents per kilowatt-hour in 1987 (3.9 cents per kilowatt-hour for firm sales and about 2.9 cents for interruptible sales). In addition to actual export sales, Ontario also shipped some 1300 GW.h of non-valued exchange electricity to U.S. utilities and received 2000 GW.h of energy on the same basis.[11]

Ontario's electricity trade surplus with the United States is almost exactly offset by a trade deficit with its neighbouring provinces. Purchases from Quebec totalled a net 5926 GW.h in 1987, with another 1050 GW.h imported from Manitoba. Ontario paid an average of 1.7 cents per kilowatt-hour for interprovincial imports in 1986 (the latest

Figure B.3

Ontario Electricity Prices
1987



SOURCE: EMR Canada, Energy Statistics Handbook.

Note: Assumes monthly bills of 1 000 kW.h residential; 300 000 kW.h commercial; 1.3 million industrial.

TABLE B.2

ONTARIO ELECTRICITY TRADE
1987

International Trade	
Exports:[a]	7 194 GW.h
Firm	265 GW.h
Interruptible	6 929 GW.h
New York	6 120 GW.h
Michigan	808 GW.h
Vermont	264 GW.h
Minnesota	3 GW.h
Imports:	111 GW.h
Balance:	+7 083 GW.h
Interprovincial Trade	
Exports (to Quebec):	16 GW.h
Imports:	6 992 GW.h
Quebec	5 942 GW.h
Manitoba	1 050 GW.h
Balance:	-6 976 GW.h
Over-All Trade Balance	+107 GW.h

SOURCES: (1) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (2) National Energy Board, Annual Report, 1988.

[a] Excludes non-marketed energy transfers.

year for which data is available).[12] This is considerably less than Ontario Hydro's average generating costs of some 2.8 cents per kilowatt-hour in 1987,[13] but this is primarily due to the fact that most interprovincial trade takes place on an interruptible basis, with imported energy flowing for short periods of time depending on the marginal demand and supply conditions in each province.

Ontario is connected to the electrical systems of other provinces and the United States through the transmission lines summarized in Table B.3. These transmission connections are much more extensive with New York State and with Michigan than they are with either of the provinces bordering on Ontario. Total transmission capacity to the U.S. of over 6600 MW was utilized at 15 percent capacity in 1987,[14] on a yearly average basis. Transmission connections with Quebec and Manitoba consist primarily of 230-kV lines, while the largest U.S.-Ontario transmission facilities have a maximum voltage rating of 345 kV.

TABLE B.3

INTERCONNECTION CAPACITY
ONTARIO, 1987[a]

New York	4100 MW
Michigan	2500 MW
Minnesota	35 MW
Quebec	1300 MW
Manitoba	260 MW

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a] Includes high-voltage lines only.

B.5.4 Emerging Issues

The relatively rapid pace of recent growth in electricity consumption in Ontario has focussed considerable attention on the plans of Ontario Hydro for future capacity expansion. If demand growth continues at its recent pace, the utility will require major capacity additions by the mid-1990s. Because of the long lead times associated with most electricity developments (particularly nuclear power, which has provided the bulk of new Ontario generating capacity over the past 15 years), Ontario Hydro is rapidly approaching a crucial decision date. Complicating the capacity situation is the fact that most of Ontario Hydro's current spare capacity is in the form of mothballed fossil-fuel steam plants. The use of these coal-fired base load plants will make it difficult for the company to meet increasingly stringent provincial restrictions on acid gas emissions, forcing Ontario Hydro to spend $2.5 billion on eight scrubbers and other pollution control improvements by the year 2000.[15] Oil-burning generating stations, meanwhile, are generally much more expensive to operate than Ontario Hydro's other facilities (depending, of course, on world oil market conditions).

Ontario Hydro recently released a draft planning strategy document[16] which analyzed the various supply and demand issues facing the utility in the coming years. This document concluded that no major new generating facilities will be required prior to the mid-1990s, as demand growth in the immediate future can be satisfied through the reactivation of mothballed facilities, the completion of the Darlington nuclear generating facility, and other interim measures. A special emphasis is placed on aggressive demand management programs and an increased reliance on independent power producers to reduce the need for expansions to the utility's inventory of central generating stations. Anticipated future supply requirements depend on the particular forecast of provincial electricity demand growth that is chosen. New facilities will be required to be in service by 1995 if a high demand growth scenario prevails (average annual growth of 4.5 percent per year), or by 1997 if the utility's 'most likely' scenario (average annual growth of just over 2 percent) comes to pass.[17] The planning document provides a variety of illustrative development plans for the utility to meet this expected demand growth, based on differing combinations of conservation, hydro development, coal-fired capacity or additional nuclear power plants (see Table B.4).

If nuclear energy were favoured as the source of future capacity expansion, the report suggests that construction of another Darlington-sized facility (four 880-MW units) would need to begin in the very near future, due to the long lead times associated with this type of development. Ontario Hydro suggests that the supply cost of new nuclear power from this type of facility would be 3.2 cents per kilowatt-hour,[18] but this estimate has been criticized by some parties, including the provincial government's own Electricity Planning Technical Advisory Panel, as being unrealistically low. Supply costs from a new coal-fired plant are estimated by Ontario Hydro at about 4.3 cents per kilowatt-hour. New hydro generating facilities would

TABLE B.4

ONTARIO HYDRO MAJOR DEVELOPMENT PROJECTS

Projects	Capacity	Year in Service
Committed Projects		
Darlington Gas Turbine	104 MW	1988
Darlington #1	881 MW	1989
Darlington #2	881 MW	1989
Darlington #3	881 MW	1991
Darlington #4	881 MW	1992
Niagara R. Hydro	540 MW	1998
Future Projects		
Further Nuclear	2000-3500 MW	
Mattagami River Hydro	379 MW	
L. Jackfish R. Hydro	132 MW	

SOURCES: (1) Energy, Mines and Resources Canada - Interfuel Substitution Demand Model; (2) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); (3) Statistics Canada, Electric Power Statistics Catalogue No. 57-202 (Ottawa, Ontario: Minister of Supply and Services Canada, various years); (4) Ontario Hydro, Annual Report and survey response; and (5) press reports.

avoid the environmental problems associated with both nuclear and coal-based generating systems, but the potential for further hydro power developments in Ontario is limited. Pending environmental approval, a large expansion to the Adam Beck generating complex on the Niagara River is expected to commence construction in 1992. The new facility would cost an estimated $1.45 billion, and would add 540 MW of firm capacity when completed in 1998.[19] Other hydro options currently under study include the Mattagami River (379 MW) and the Little Jackfish River (132 MW), with supply cost estimates for these projects ranging between 3.9 and 4.4 cents per kilowatt-hour.

The tough choices facing Ontario Hydro over future supply sources has made the prospect of increased interprovincial trade in electricity particularly appealing. Ontario Hydro has signed an agreement with Manitoba Hydro for the provision of 200 MW of firm electricity between 1998 and 2003, up to a total quantity of 5600 GW.h.[20] The abundant hydro resources of its neighbouring provinces could be a feasible alternative to the expansion of generating capacity within Ontario's borders. Moreover, negotiations with Hydro-Quebec for a much larger long-term purchase of electricity have been a top priority for Ontario Hydro for the last year. Ontario's original proposal to purchase an equity share in a new Quebec hydro development has been rejected, and negotiations now centre on the price and terms of a more traditional long-term firm sales contract, believed to be in the 2000-MW range. A major reliance on interprovincial imports appears unlikely, however, since Ontario Hydro is probably unwilling to match the high prices offered for Quebec's electricity by the utilities of the northern United States. In addition, the Ontario government may wish to ensure that most of the employment and industrial spin-offs of future supply developments remain within the province, and might therefore opt for domestic supply developments on the basis of their macro-economic benefits.

Even before the construction of new facilities begins early in the next decade, Ontario Hydro already finds itself in the midst of an ambitious investment program. Current spending on fixed assets is running at just over $2.6 billion per year--almost as much as all other electric utilities in Canada combined.[21] Most of this is currently dedicated to the completion of the Darlington nuclear power facility, which is scheduled to begin producing power in 1989. Another $500 million will be required over the next 4 years to complete the re-tubing of the Pickering 3 and 4 reactors, a task that was originally scheduled for the late 1990s but which was accelerated by test results showing a faster-than-expected deterioration of tubing in the two reactors.

Demand management and small-scale electric production are also being introduced by Ontario Hydro to help postpone the need for new, large-scale facilities. The utility is implementing a reform of its rate schedules for direct industrial consumers to include time-of-day rates during the peak winter demand season, beginning in January 1989. It is hoped that these and other measures, including $250 million worth of grants and low-interest loans for energy efficiency improvements by consumers, will shave as much as 3500 MW from total demand by the year 2000. Similarly, the promotion of cogeneration facilities amongst industrial users--already responsible for 500 MW of power in Ontario, with further undeveloped potential estimated at more than 2000 MW--could also help to defer the construction of new central generating facilities. One innovative proposal being implemented will see Inter-City Gas build a $100 million cogeneration facility near the Boise Cascade pulp and paper plant at Fort Frances. Inter-City will sell the steam to the pulp company and 87 MW of electricity to Ontario Hydro.[22] This development could serve as a prototype for larger parallel generation developments in subsequent years.

Many options have been surveyed by the Ontario Hydro strategy document, but no clear answers present themselves. Electricity demand in the province in recent years has consistently outpaced the utility's most-likely demand predictions, forcing a series of upward revisions in these planning forecasts. The threat of future power shortages looms closer with each passing year,[23] but there is no emerging consensus as to how that threat will be answered--with environmentally unpopular nuclear or coal-fired facilities, with the uncertain prospects of demand management, with relatively expensive natural gas generators, or with the high capital costs of developing the province's few remaining hydroelectric sites. The sheer magnitude of the Ontario Hydro system means that even moderate demand growth will necessitate capacity additions in the next decade measured in many thousands of megawatts, and so it is perhaps in Ontario, more than anywhere else in Canada, that the high financial and environmental costs associated with continued expansion of the electricity system will be felt first, and most acutely.

Footnotes

[1] Ontario Hydro, Annual Report, 1987, p. 34.

[2] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), pp. 21 and 49.

[3] Ontario Hydro, Annual Report, 1987, p. 21.

[4] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 23.

[5] Ibid., p. 21.

[6] Statistics Canada, Quarterly Report on Energy Supply-Demand in Canada, Catalogue No. 57-003 (Ottawa: Minister of Supply and Services Canada, various years), Table 8B.

[7] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 65; and Toronto Star, October 21, 1988, p. A12.

[8] National Energy Board, Annual Report, 1987, p. 99.

[9] This level of firm exports would require about 40 MW of capacity to be dedicated to firm export sales, assuming a 75 percent capacity utilization rate.

[10] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 44.

[11] National Energy Board, Annual Report, 1987, p. 99; and Energy, Mines and Resources Canada, Electric Power in Canada: 1987, pp. 51 and 91.

[12] Statistics Canada, Electric Power Statistics, Catalogue No. 57-202 (Ottawa, Ontario: Minister of Supply and Services Canada, 1986), p. 12.

[13] Weighted average, based on data published in Ontario Hydro, Annual Report, 1987, p. 47.

[14] Average annual power flow associated with total electric energy exports of 8497 GW.h (including service exchanges) is less than 1000 MW.

[15] Energy Analects, vol. 18, no. 6, February 13, 1989.

[16] Ontario Hydro, Meeting Future Energy Needs: Draft Demand/Supply Planning Strategy, Ontario Hydro System Planning Division, December 1987.

[17] Since actual demand growth in the last 5 years has been much closer to the high-growth scenario, Ontario Hydro has recently

increased its most-likely demand forecast. This implies that new facilities would be required by about the middle of the next decade even in the most-likely scenario.

[18] Supply cost data reported in Energy Analects, February 22, 1988.

[19] Information supplied by the Electric Energy Branch, Energy, Mines and Resources Canada.

[20] Energy Analects, vol. 16, no. 41., October 19, 1987.

[21] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 60.

[22] Ontario Hydro, Annual Report, 1987, pp. 21-22; and Toronto Star, January 31, 1989.

[23] Ontario Hydro Chairman Robert Franklin recently warned of the possibility of power rationing in the province by the mid-1990s unless a major new generating station is approved by the provincial government in 1989; see the Toronto Star, October 7, 1988.

B.6 QUEBEC

As a result of its natural endowment of hydroelectric potential as well as the aggressive marketing of electricity both in and outside of the province, Quebec is the largest producer, consumer and exporter of electric power in Canada. These results are fully consistent with the long standing policy of the Government of Quebec which clearly identifies the important role that electricity--as the "engine of growth"--occupies within the long-term development plans of the province.

B.6.1 Industrial Structure

Hydro-Quebec is a Crown corporation established by the provincial legislative assembly in 1944 through the nationalization and amalgamation of two privately owned Montreal utilities--Montreal Light, Heat and Power Consolidated and Beauharnois Light, Heat and Power Company. It has since acquired all other electric utilities within the province, becoming the sole utility responsible for the generation, transmission and distribution of electric power in Quebec.

The list of Hydro-Quebec's wholly-owned subsidiaries include the following: The Societe d'energie de la Baie James, which carried out construction of the first phase of the La Grande complex; Hydro-Quebec International, which provides engineering and consulting services abroad for electric power projects; Cedar Rapids Transmission Company Limited, which transmits export power to New York State; and Nouveler Inc., which promotes energy efficiency and alternative energy sources. Hydro-Quebec is also a shareholder in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant. Hydro-Quebec, which serves over 2.6 million customers and employs 18,000 full-time personnel, had combined assets worth over $31 billion in 1987 and revenues from electricity sales of over $5 billion.

As is the case for most other Canadian utilities, the regulation of hydro rates and construction of new facilities in Quebec is the responsibility of the provincial government. More specifically, a committee of the National Assembly on Labour and the Economy reviews Hydro-Quebec's long-term development plan, which includes any proposed rate changes. The committee then recommends to the Ministry of Energy and Resources, which in turn makes a recommendation to cabinet. Rate increases can therefore be implemented by Hydro-Quebec only after they have been approved by Cabinet.

The construction of new facilities by Hydro-Quebec can take place only after the utility has received an Order In Council from the provincial government. Before such an order is issued, the Department of Environment and the Department of Energy and Resources must approve plans for the new facility. Other departments and agencies are also consulted.

B.6.2 Supply/Demand Balance

In 1987, Hydro-Quebec had a total installed generating capacity of 24 533 MW, as well as access to most of the generating output of the Churchill Falls power plant, bringing total available generating capacity to 29 733 MW (see Table B.1). Almost all of this generating capacity was required to meet a peak demand of 26 005 MW. Left with a reserve capacity of roughly 3700 MW, Hydro-Quebec had the lowest reserve margin--14 percent--of any electrical utility in Canada. Aside from the relatively modest magnitude of the reserve capacity in the province, the extent of the reliance on hydro generation is perhaps the most distinguishing feature of the electric power industry in Quebec. As indicated by Figure B.1, approximately 94 percent of total capacity and electricity generation in Quebec is accounted for by hydro sources. Furthermore, all major future additions to Hydro-Quebec's system, including those planned as well as those currently under construction, involve hydro generation. The majority of Hydro-Quebec's 53 hydroelectric generating stations have installed capacities in excess of 100 MW, with the ten largest hydro stations including La Grande 2, 3 and 4 (10 200 MW) accounting for roughly 42 percent of the total generating capacity within the province.

Total generation in the province of Quebec, as indicated by Figure B.1, was 156 952 GW.h in 1987, of which 29 183 GW.h were exported to other provinces or the United States. In turn Quebec imported 30 427 GW.h of power, mostly from Newfoundland, to support total provincial electricity consumption of 158 196 GW.h. A sectoral breakdown of total consumption is provided in Figure B.2. As indicated, the industrial sector accounted for 48 percent of total consumption in the province, while the residential and commercial sectors accounted for 27 percent and 17 percent of total consumption, respectively. Hydro-Quebec expects electricity demand in the province to grow at an annual average rate of 2.7 percent over the 1988-2006

TABLE B.1

ELECTRICAL GENERATING CAPACITY AND RESERVE
QUEBEC
1987

Installed Capacity	29 733 MW
Available Capacity Firm[a]	24 533 MW
Peak Demand	26 005 MW
Reserve Capacity	3 728 MW
Reserve Ratio[b]	14 %
Load Factor[c]	65.5 %

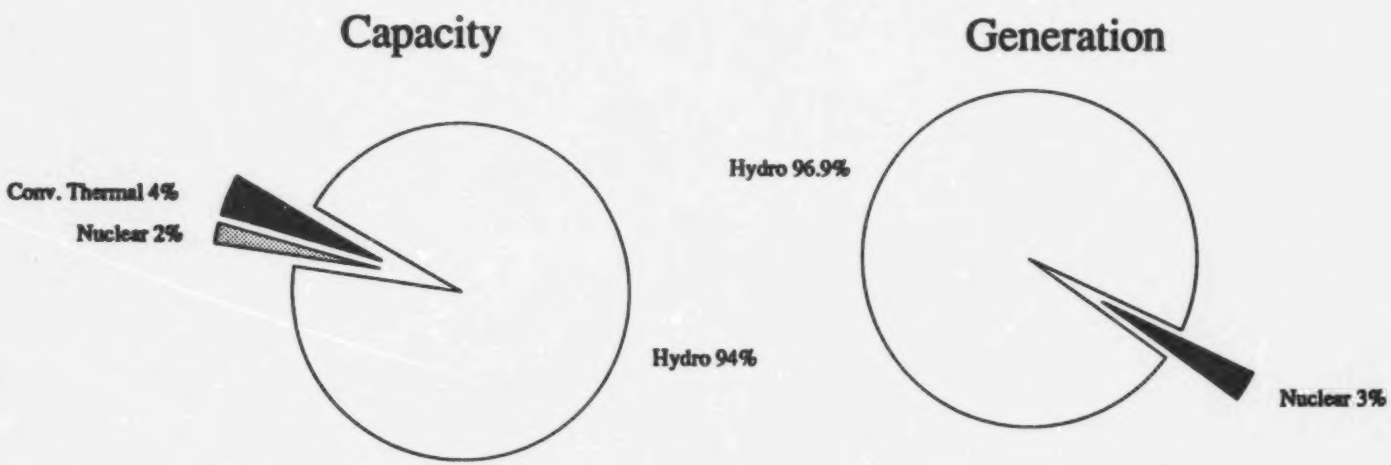
SOURCES: (1) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (2) Hydro-Quebec, Development Plan 1988-1990.

[a] Differences between installed and available generating capacity may be caused by a number of factors. These include the water levels in the reservoirs, the fact that not all equipment can be placed on line at the same time, and the fact that some equipment may be out of service for some reason.

[b] Reserve ratio is defined as the reserve capacity divided by peak demand.

[c] Load factor is defined as the ratio of average load during some designated time period to maximum load during the same time period.

Figure B.1
Quebec Electricity Supply
1987

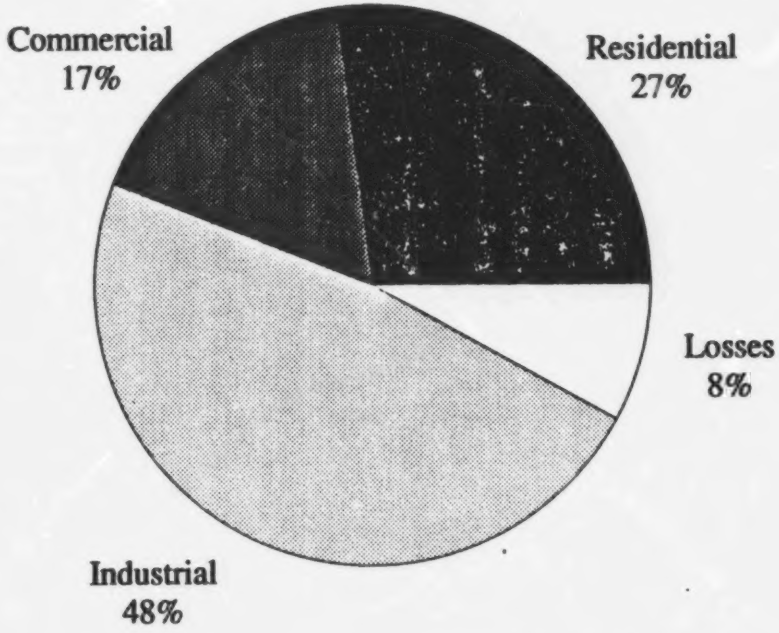


Total Capacity: 28 407 MW

Total Generation: 156 952 GW.h

SOURCE: EMR, Electric Power in Canada, 1987. NOTES: Oil accounted for 0.1% of total generation in 1987.

Figure B.2
Quebec Electricity Demand
1987



Total Consumption: 158 196 GW.h

SOURCE: Statistics Canada, Quarterly Report on Energy Supply and Demand 1987-IV, (Cat. 57-203).

period, with much of this growth being led by increased demand for electricity from the industrial sector.[1] The utility's 1988-1990 development plan calls for average annual increases in electricity consumption within the industrial sector of 3.8 percent, with growth rates for the commercial and residential sectors of 2.8 percent and 1.5 percent, respectively. While a significant reduction in off-oil conversions in the residential sector explains the relatively low growth rates expected from this sector over the coming decade, aggressive marketing combined with very attractive electricity pricing accounts for much of the expected increases in industrial electricity demand.

Electricity rates for the residential, commercial and industrial sectors in Quebec are contained in Figure B.3. As indicated, Quebec's rates fall below the national average in each of the three categories. Quebec's industrial rates of 3.10 cents per kW.h are the lowest in the country, next to Manitoba's, and an obvious incentive for energy intensive industries like aluminum reduction and pulp and paper to locate in the province. The current price of electricity in Quebec is also attracting customers outside of the province as reflected in the increasing importance of electricity exports, discussed below.

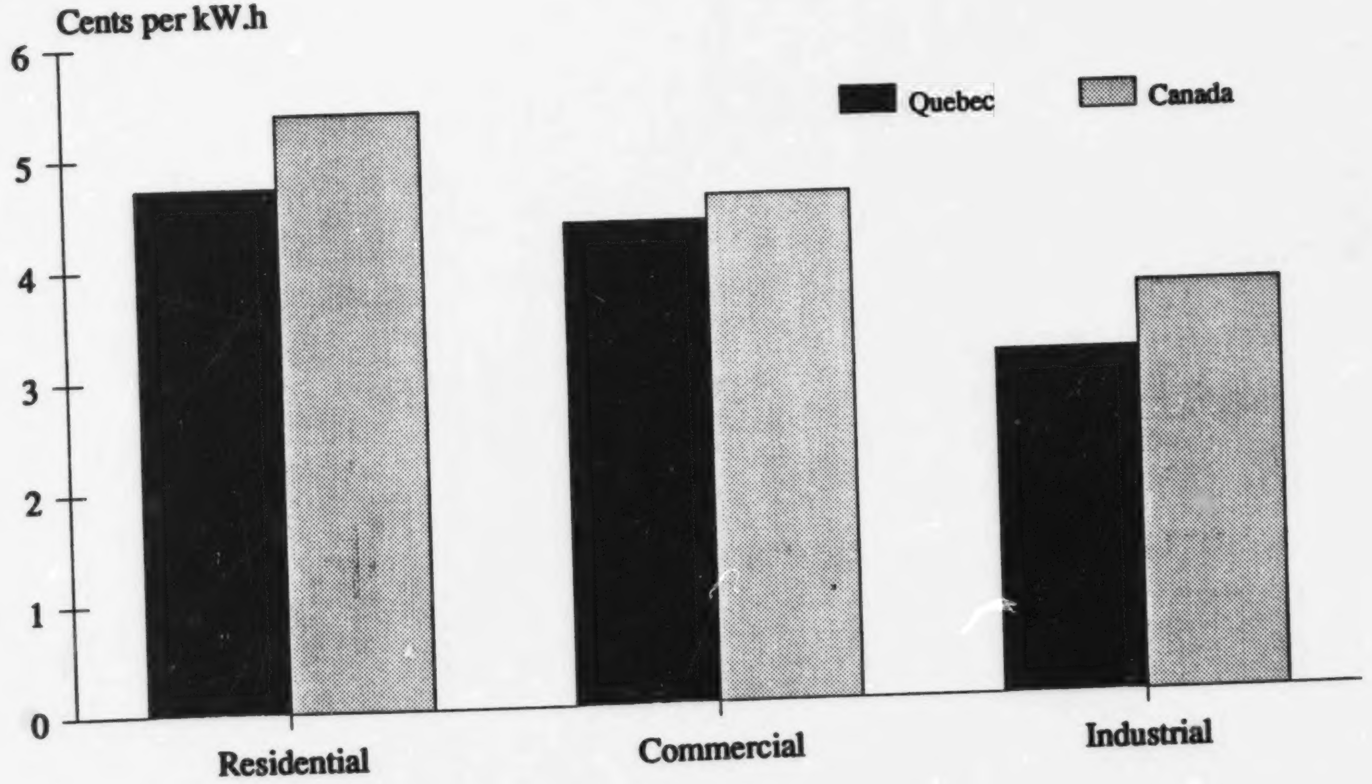
B.6.3 Electricity Trade

A variety of information concerning the trade of electric power in Quebec is presented in Table B.2, where perhaps the most striking piece of information relates to total net exports. As indicated, Quebec's overall trade deficit in electric power has decreased from 11 799 GW.h in 1983 to 1244 GW.h in 1987, as a result of rising interprovincial and international exports. Interprovincial exports of 12 782 GW.h in 1987 were confined to New Brunswick (53 percent) and Ontario (47 percent). International exports, equal to roughly 16 401 GW.h in 1987, were concentrated in the state of New York (59 percent), New England (29 percent) and Vermont (12 percent). Revenues from the export sale of electricity to the United States totalled $445 million in 1987.

As indicated in Table B.2, average export revenues vary considerably with destination and type. By far the highest average revenues--4.3 cents per kW.h--are earned on the sale of firm power exports to the U.S. markets. This explains the interest of the provincial utility in increasing the volume of firm exports which currently account for less than one third of total exports.

Figure B.3

Electricity Prices in Quebec
1987



SOURCE: EMR Canada, Energy Statistics Handbook.

TABLE B.2

QUEBEC ELECTRICITY TRADE: SELECTED DATA
1983-1987

Year	Exports (GW.h)	Imports (GW.h)	Net Exports (GW.h)	Total Net Exports (GW.h)
Interprovincial Trade				
1987	12 782	30 427	-17 645	
1986	14 496	30 712	-16 216	
1985	14 491	31 878	-17 387	
1984	11 668	36 105	-24 437	
1983	9 371	31 290	-21 919	
International Trade				
1987	16 401	-	16 401	-1 244
1986	12 674	35	12 639	-3 577
1985	9 581	3	9 578	-7 809
1984	11 250	8	11 242	-13 195
1983	10 128	8	10 120	-11 799

Destination of Exports 1987

Maine	xxx
New Hampshire	xxx
Vermont	1 914 GW.h
New England	4 773 GW.h
New York	9 712 GW.h
Total U.S.	16 401 GW.h
New Brunswick	6 840 GW.h
Ontario	5 942 GW.h
Total Provincial	12 782 GW.h

Source of Imports 1987

Newfoundland	30 400 GW.h
(avg. price = 0.29 cents per kW.h)	

Additional Information 1987

U.S. Export Revenues	$445 million
Average Revenues	
Other Provinces	
firm:	$2.25 (cents per kW.h)
surplus:	$1.79 (cents per kW.h)
United States	
firm:	$4.30 (cents per kW.h)
surplus:	$2.36 (cents per kW.h)
Firm Exports	32 (% of total exports)
Interruptible Exports	68 (% of total exports)

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

NOTE: xxx - negligible quantities.

Hydro-Quebec has been particularly active in electricity trade in recent years, consolidating its position on the export market by negotiating long-term deliverables of firm power. In particular, several major long-term agreements were signed over the last 2 years including a major contract with Vermont Joint Owners, providing deliveries up to a possible 500 MW of firm power between 1990 and 2015 with associated revenues of approximately $8.6 million, and a major agreement in principle with the New York Power Authority for the sale of two blocks of 500 MW of firm power between 1995 and 2016, capable of generating an estimated $17 million in export revenues. These new commitments have enabled the utility to realize a substantial portion of its current export sales objective to export 3500 MW of firm power before the year 2000.

In the area of interprovincial trade, Quebec is exploring opportunities for the sale of firm power to the province of Ontario, which has expressed the desire to meet part of its growing electricity requirements through Quebec-sourced power. Ontario has also indicated an interest in entering into joint investment projects within the province of Quebec.

In addition to the long-term contracts for firm power discussed above, Hydro-Quebec has recently concluded several agreements with neighbouring systems in Canada and the United States involving interruptible supplies of power that will enable it to sell all of its expected surplus power and energy until 1995.

B.6.4 Emerging Issues

In its new energy policy announced on September 1988, the government of Quebec made a commitment to promote electricity exports. This move followed on the heels of a new export policy introduced by the Government of Canada in September 1988, enthusiastically supported by Quebec, which serves to streamline and liberalize existing federal legislation pertaining to the export of electric power in Canada. In order to meet these export objectives, while at the same time responding to growing internal electricity demands, Hydro-Quebec will have to move aggressively to develop new generating installations and upgrade existing transmission facilities.

The province's current development plan is contained in Table B.2. Among Hydro-Quebec's preferred options are: La Grande Phase II (2464 MW); Ste. Marguerite River (822 MW); Grande Baleine (2891 MW); Ashuapmuchuan River (550 MW); Laforge-2 (270 MW);

Eastmain-1 (510 MW); Nottaway-Broadback-Rupert (8700 MW); and La Romaine River (1710 MW). The scheduled development of these and other planned projects in the province may sustain a significant volume of electricity exports for some years in addition to meeting internal needs. It is worth noting, however, that even if electricity demand within the province grows at the modest rate of 2.7 percent per annum, all of the additional capacity supplied by these and other projects contained within the current plan will be required by the year 2008, just to meet growing electricity requirements from within the province. Thus the extent to which Quebec can continue to vigorously promote the use of electricity within the province and, at the same time, aggressively develop its export markets, is a matter of some uncertainty.

Unmentioned, but clearly on Hydro-Quebec's list of most preferred future development sites, is the 1700-MW Gull Island site in Labrador--perhaps the most economical, as of yet undeveloped hydro site remaining in Canada. To the extent that Quebec is successful in obtaining future export contracts, the opportunity for the early development of Gull Island is evident. Discussions between Quebec and Newfoundland regarding the development of Gull Island are currently underway.

The Churchill Falls complex is Canada's largest hydroelectric generating facility, second only to LG-2 in James Bay in terms of energy output. Under the existing contract between the provinces of Quebec and Newfoundland, which does not expire until the year 2041, over 90 percent of the total output of Churchill Falls flows into Quebec at prices around .29 cents per kW.h. Of the total capacity of 5225 MW at Churchill Falls, Newfoundland can recall only 300 MW for its own use, while an additional 225 MW is reserved for use in Labrador.

Over the past 12 years, Newfoundland has taken a number of legal actions to have the Churchill Falls contract changed to incorporate higher electricity prices. The most recent effort of this nature was concluded on June 9, 1988 when the Supreme Court of Canada ruled that Newfoundland could not recall power from Churchill Falls beyond the limits specified in the contract with Hydro-Quebec. Newfoundland has no further legal actions pending.

Following the most recent Supreme Court decision, Newfoundland and Quebec agreed to begin a new round of talks. Quebec's primary objectives in this regard are to obtain a new agreement regarding the management of the existing site at Churchill Falls, and to obtain additional power from the undeveloped resources in Labrador.

In addition to developing new capacity, either within the province or in Labrador, Hydro-Quebec will have to upgrade its transmission facilities if it hopes to attract additional export orders. Indeed, recent studies conducted by the Mid-Atlantic Area Council of the North American Reliability Council (NERC) have indicated concern over the reliability of performance of the Hydro-Quebec network, which has experienced as many as eight complete system collapses over the 1971 to 1984 time period. This record is poorer than that of any other interconnected network within the NERC.

As is the case with several utilities in other provinces, Hydro-Quebec is currently receiving interest from the business community to accommodate greater private sector participation in the generation of electricity within the province. While the potential contribution to the total electricity supply within the province from small, independently-owned and operated generating stations is modest,[2] the province of Quebec has recently announced--as part of its new energy policy--that Hydro-Quebec is to sell 100 small generating stations (25 MW and less) to the private sector. The latter will invest $500 million in the refurbishing and upgrading of the existing stations.

Footnotes

[1] Hydro-Quebec, Development Plan 1988-1990: Horizon 1997, March 1988.

[2] Recent estimates suggest that private generation could conceivably contribute 400 MW of capacity to the province's total generating capacity.

B.7 NEW BRUNSWICK

The electricity system of New Brunswick is one of the most diverse and interesting provincial systems in Canada. The province is the largest consumer of electricity amongst the Atlantic Provinces, and next to Newfoundland is the second-largest producer in the region. While New Brunswick generated only 2.6 percent of Canada's electricity in 1987, the province accounted for 13 percent of total Canadian electricity exports, with U.S. sales totalling almost 6000 GW.h.[1] Through an intricate and active network of trading relationships with neighbouring provinces and the United States, a large quantity of electric energy crosses New Brunswick's borders each year, yet ironically the province's domestic generation is almost exactly equal to its in-province consumption. Another unique aspect of New Brunswick's electricity system is its reliance on nuclear power; the Point Lepreau CANDU generator was responsible for some 40 percent of total electricity generation in the province in 1987.

B.7.1 Industrial Structure

The New Brunswick Electric Power Commission, more commonly known as NB Power, is the dominant producer and distributor of electricity in the province. It was created by an act of the Provincial Legislature in 1920, at which time the electricity industry in New Brunswick was fragmented among at least twenty different private and municipally-owned utilities. NB Power generates electricity from its 14 power plants, which reflect a balanced mixture of coal, oil, nuclear and hydroelectric facilities. Electricity is sold by the Commission to over 250,000 direct customers, as well as 40,000 indirect customers who are served by municipally-owned distribution utilities in the cities of Saint John and Edmundston.[2]

As a Crown corporation, NB Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a 9-member board appointed by the provincial government, of which both the Chairman and the Vice-Chairman of NB Power are members. A committee of the Legislature that monitors publicly-owned corporations also reviews the activities of the corporation on an annual basis. New construction projects of the corporation must receive environmental impact approval from the

Minister of Municipal Affairs and the Environment, who makes a decision on the basis of an environmental assessment.

In April 1986, NB Power acquired another provincial Crown corporation, N.B. Coal, for one dollar.[3] NB Power purchases all of the output of this new subsidiary as feedstock for its coal-fired generating stations.

B.7.2 Current Supply/Demand Balance

NB Power currently possesses a total installed generating capacity of just under 3200 MW (see Table B.1). Available capacity is somewhat lower than this figure, because one-third of the 630-MW Point Lepreau nuclear reactor is dedicated to the supply of New England utilities until 1991. In addition, the P.E.I.-based Maritime Electric Co. owns a 10 percent share in a NB Power 200-MW coal/oil generating unit at Dalhousie. Compared to 1987 peak demand of just under 2200 MW, this available capacity leaves a reserve margin of some 750 MW, for a reserve ratio of over 35 percent.

TABLE B.1

NB POWER SYSTEM
CAPACITY AND RESERVE, 1987

Installed Capacity	3190 MW
Available Capacity[a]	2946 MW
Peak Demand	2178 MW
Reserve Capacity	768 MW
Reserve Ratio	35.3 %
Load Factor[b]	63.9 %

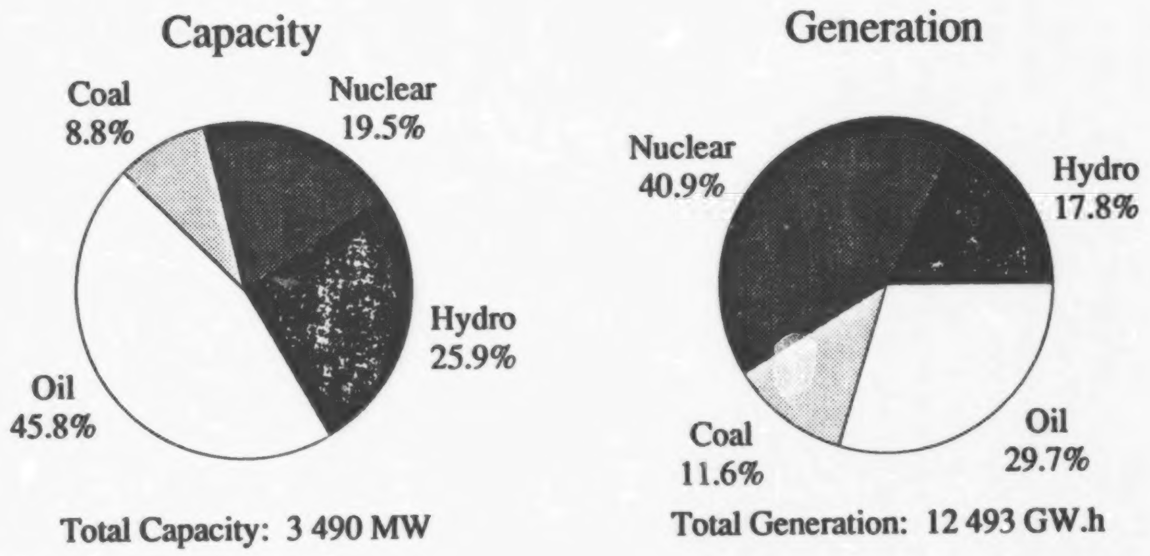
SOURCES: NB Power Annual Report and response to Energy, Mines and Resources Electricity Branch questionnaire; and Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa, Ontario: Minister of Supply and Services Canada, 1988).

[a] Excludes share of Point Lepreau and Dalhousie generating facilities that are dedicated to adjacent utilities.

[b] Average hourly energy sales as a share of annual peak demand.

Over 40 percent of the electricity generated by NB Power in 1987 was produced at the Point Lepreau nuclear generating station, which accounts for less than one-fifth of the utility's installed capacity (see Figure B.1). Point Lepreau's disproportionate contribution to NB Power's energy requirements is the result of its very high rate of capacity utilization--the highest of any commercial nuclear station in

Figure B.1
New Brunswick Electricity Supply
1987



SOURCE: EMR, Electric Power in Canada.
Note: Includes private and industrial
electricity production.

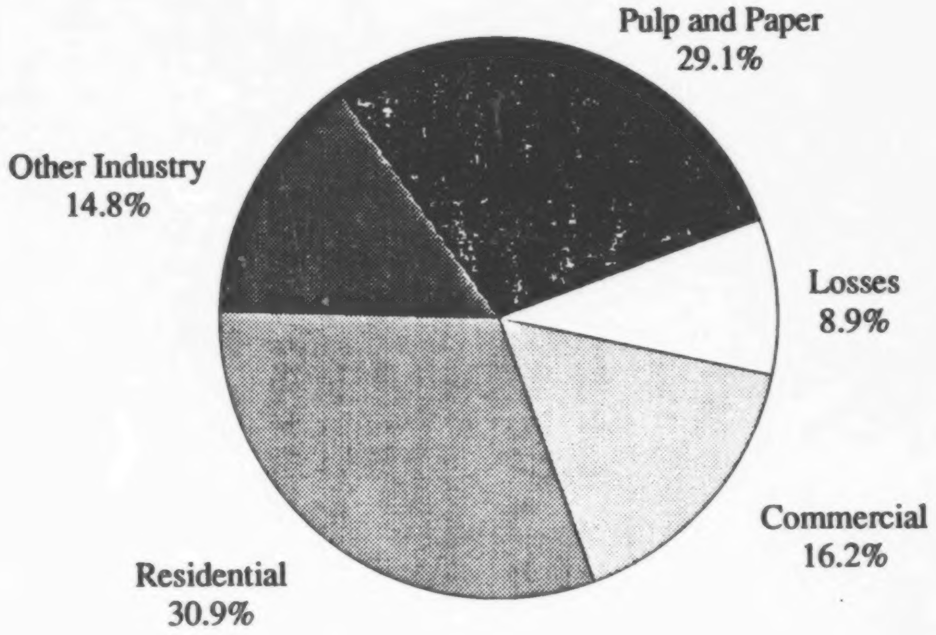
the world between 1983 and 1986.[4] Oil and coal-fired facilities produced 30 percent and 12 percent, respectively, of total generation in 1987. NB Power's six hydroelectric facilities, all of which are located in the west of the province near the U.S. border, generated some 18 percent of provincial electricity production in 1987. One large hydraulic facility, the 650-MW Mactaquac development, accounts for three-quarters of the province's total hydroelectric capacity.

The generating facilities of NB Power are supplemented by a small amount of private industrial generating capacity. These facilities account for about 300 MW of capacity (primarily in the form of conventional thermal generating units) and produce some 800 GW.h of energy per year, or less than 7 percent of total provincial output.[5] Virtually all of this industrial output is utilized by the generating companies themselves, primarily in pulp and paper operations.

In terms of electricity demand, New Brunswick ranks third among Canadian provinces--behind only Quebec and British Columbia--in its per capita consumption of electricity. This is rather surprising, given the relatively high electricity prices which are characteristic of all of the Atlantic Provinces, including New Brunswick. Total provincial demand in 1987 totalled some 12 400 GW.h, equivalent to over 17 000 kW.h per person per year.[6] New Brunswick's industries, especially its large pulp and paper sector, consume the largest share of electricity supply in the province (see Figure B.2), accounting for almost 44 percent of total provincial demand. The residential market consumes another 30 percent of the electricity pie, while the commercial sector is responsible for a relatively small 16 percent of aggregate consumption.

Recent electricity demand growth in New Brunswick has been much higher than the average for Canada as a whole. Provincial demand increased by 6.2 percent in 1987--higher than any other province in Canada--on top of a startling 11 percent demand increase experienced in 1986.[7] Strong industrial demand accounts for much of this demand growth, as does the increasing number of residential conversions to electric space heating from older and more expensive oil-fired furnaces. For the period 1987-2005, only Alberta and Nova Scotia are expected to experience average demand growth exceeding that of New Brunswick. NB Power's own estimates show energy and peak demand growth averaging 2.6 percent and 3.0 percent, respectively, over the next two decades.

Figure B.2
New Brunswick Electricity Demand
1987



Total Consumption: 12 039 GW.h

SOURCE: Statistics Canada Quarterly
Report on Energy Supply-Demand.

As is the case for the other Atlantic Provinces, New Brunswick's power rates are markedly higher than the national average (see Figure B.3). The difference between provincial rates and the national average is greatest for commercial customers, partially accounting for the unusually small share of that sector in total provincial consumption.[8]

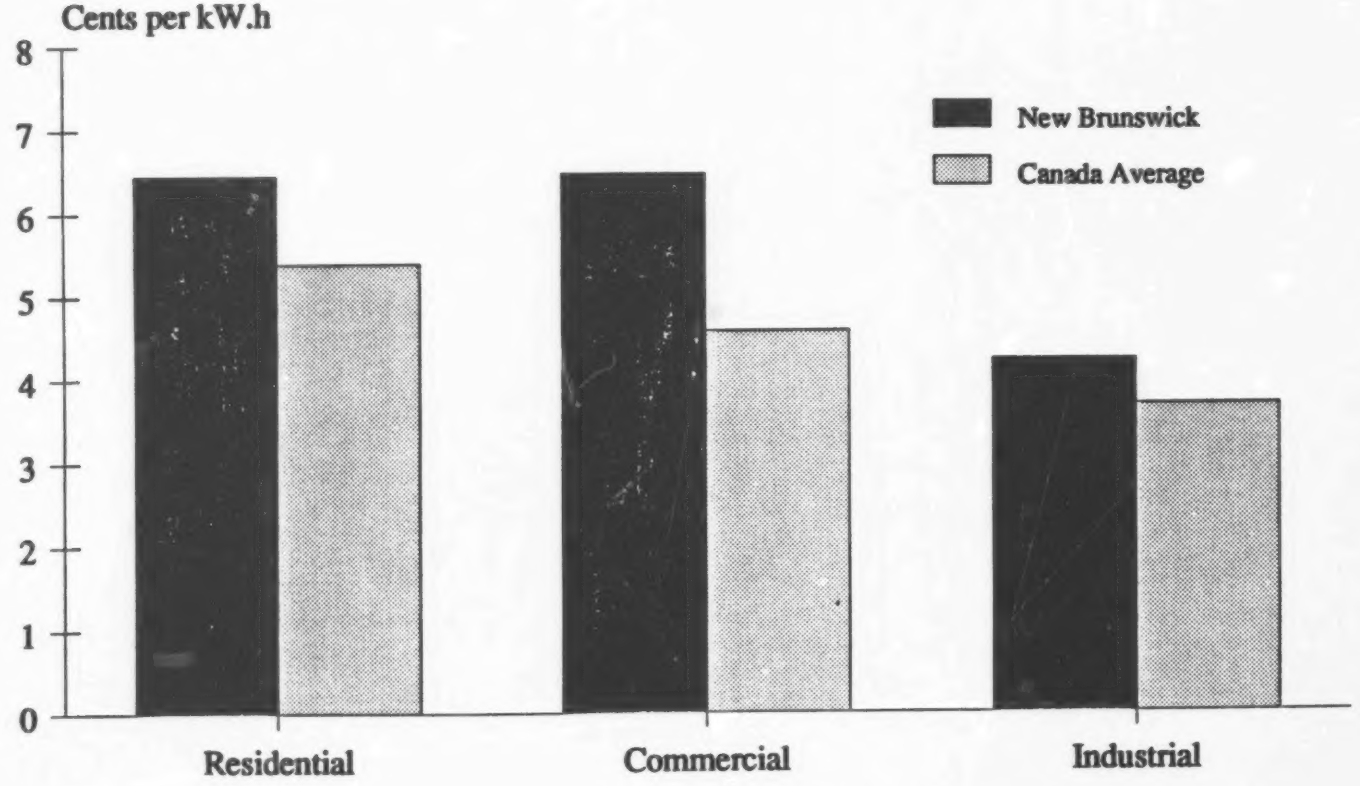
B.7.3 Electricity Trade

New Brunswick has developed an active and sophisticated trading relationship with electric utilities, both in adjacent provinces and in the United States. While on balance the province is self-sufficient in electricity production, traded electricity nevertheless constitutes a substantial proportion of the energy handled by NB Power. New Brunswick both imports electricity from other provinces (primarily Quebec) and exports to the United States (primarily to Maine), so that in 1987 its imports and its exports each accounted for a full 50 percent of domestic generation. New Brunswick has been able to profit from the price difference between the electricity it purchases from other provinces and its own exports to the U.S. NB Power's sales to the U.S. in 1987 received more revenue per kilowatt-hour than any other province's exports, garnering a total of some $275 million in export income for the province.[9]

Table B.2 provides a breakdown of energy sales from New Brunswick to adjacent markets. Roughly 70 percent of the province's U.S. sales were destined for the Maine market, with the remainder sent to Massachusetts. Almost 40 percent of these exports consisted of firm sales in 1987, a significantly higher proportion of firm sales than is the case with other Canadian electricity exporters. Over 98 percent of New Brunswick's electricity imports originated in Quebec.

Table B.3 lists the interconnection capacity that has been installed between New Brunswick and adjacent electricity systems. Interprovincial interconnections with transmission capacities of 1000 MW, 900 MW and 200 MW link New Brunswick with the provinces of Quebec, Nova Scotia and Prince Edward Island, respectively. In turn, seven different interconnections with Maine utilities provide for a total of more than 800 MW of transmission capacity to the United States. Most of this transmission takes place over a single 345-kV, high-voltage interconnection with a capacity of 600 MW. This interconnection is expected to be sufficient to handle the international energy flow associated with existing export contracts and additional deals currently under negotiation. NB Power is nevertheless investigating the

Figure B.3
New Brunswick Electricity Prices
1987



SOURCE: EMR Canada, Energy Statistics Handbook.

Note: Assumes monthly bills of 1 000 kW.h residential; 300 000 kW.h commercial; 1.3 million kW.h industrial.

TABLE B.2

NEW BRUNSWICK ELECTRICITY TRADE
1987

International Trade:	
Exports:[a]	5910 GW.h
Firm	2319 GW.h
Interruptible	3590 GW.h
Maine	4096 GW.h
Massachusetts	1813 GW.h
Net Exports:[b]	5893 GW.h
Interprovincial Trade:	
Exports:	1164 GW.h
Nova Scotia	659 GW.h
P.E.I.	483 GW.h
Imports:[c]	6922 GW.h
Net Imports:	5758 GW.h
Over-All Trade Balance:	152 GW.h

SOURCES: (1) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (2) National Energy Board, Annual Report, 1987.

[a] Excludes non-marketed energy transfers.

[b] Imports from the U.S. totalled 17 GW.h.

[c] 82 GW.h were imported from Nova Scotia; all the rest were purchased from Quebec.

feasibility of a second 345-kV link between Point Lepreau and Orrington, Maine, that would eventually triple international transmission capacity.[10] New Brunswick would like to complete the first phase of this expansion by 1992.

TABLE B.3

INTERCONNECTION CAPACITY
NEW BRUNSWICK, 1987

Maine	815 MW
Quebec	1000 MW
Nova Scotia	600 MW
P.E.I.	200 MW

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

New Brunswick's electricity trade is set to grow significantly in future years on the strength of several interesting contracts that have been signed or initiated in recent months. In November 1987, New Brunswick struck a deal with Hydro-Quebec to supply it with up to 3000 GW.h of firm electricity per year (starting in 1988 and running until 1992), with a further 2000 GW.h per year of energy available in 1993 and 1994. The deal is worth an estimated $650 million, and would help NB Power meet up to 50 percent of its expected growth in domestic demand between now and 1993.[11] As a result of this contract, New Brunswick withdrew its objections to Hydro-Quebec's major New England export contract in hearings before the National Energy Board.

A second precedent-setting contract was signed between New Brunswick, Quebec, and Prince Edward Island in August 1988, to supply the Island with up to 50 MW of power from the two mainland provinces over the next 6 years.[12] Under the arrangement, the P.E.I. utility Maritime Electric will purchase a mixture of firm hydroelectric power from Quebec and interruptible supplies from New Brunswick thermal plants. P.E.I. had earlier approached New Brunswick with a request to directly wheel Quebec power through New Brunswick to the Island; NB Power's cooperation with the arrangement was secured only after it was guaranteed a share of the P.E.I. market for its own plants, which have supplied up to 90 percent of P.E.I.'s electricity demand in recent years.

In the international market, New Brunswick continues to explore the possibility of further expansion in its sales to New England. NB Power is currently negotiating with New England utilities regarding a possible renewal of the agreement to lease some 200 MW of the Point Lepreau plant's capacity for dedicated firm power exports; the current agreement expires in 1991. The Premier of New Brunswick also recently offered the New England states up to 600 MW of additional firm capacity from coal and nuclear plants in the province.[13]

B.7.4 Emerging Issues

New Brunswick's demand for electricity has shown very rapid growth in recent years. Combined with the brisk business done by the province in the export market, this has forced NB Power to review several options for a major expansion of its generating facilities. The only definite decision announced so far by the utility is a plan to construct a new 450-MW, coal-fired thermal unit, expected to be completed by 1993. The location for this facility has not yet been chosen. Beyond this facility, and despite its recent purchase of firm power from Quebec, the utility expects that it will require an additional 400 MW of capacity by about 1997. One option under consideration to help meet this demand would be the conversion of the under-utilized 1000-MW, oil-fired Coleson Cove plant to the use of Venezuelan `orimulsion' (a mixture of bitumen, water and emulsifying agents). A second possibility is the expansion of hydroelectric facilities on the Saint John River, adding a potential 440 MW of capacity. This project would result in extensive upstream flooding in Maine and Quebec, and would therefore require the approval of their respective governments to proceed. Also under consideration by NB Power is the construction of a second nuclear generating unit at Point Lepreau.

As environmental protection becomes an increasingly significant constraint on the Canadian electricity industry, New Brunswick may have to reconsider its reliance on coal and heavy oil as fuels for its power plants. Strict new federal/provincial standards for sulphur dioxide emissions, scheduled for enforcement by 1994, have met with public opposition recently from NB Power, which argues that the new pollution emission targets are too low and would harm the provincial coal industry.[14] As part of an effort to reduce its emissions, the utility plans to fuel its new 450-MW, coal-fired plant with low-sulphur coal.

Footnotes

[1] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), p. 23.

[2] NB Power, Annual Report, 1986-87, p. 5.

[3] Ibid., p. 30. The purchase price also included the assumption of N.B. Coal's $6 million long-term debt and other liabilities.

[4] Ibid., p. 8.

[5] Statistics Canada, Electric Power Statistics, Catalogue No. 57-202, Vol. II (Ottawa, Ontario: Minister of Supply and Services Canada, various years).

[6] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 23.

[7] Ibid., p. 21.

[8] Energy, Mines and Resources Canada, Energy Statistics Handbook (Ottawa, Ontario: Minister of Supply and Services Canada, various years), Tables 7.19-7.21.

[9] National Energy Board, Annual Report, 1987; and Statistics Canada, Electric Power Statistics, Catalogue No. 57-202.

[10] The Times-Transcript, October 27, 1988, p. 1.

[11] Energy Analects, vol. 16, no. 47, November 30, 1987.

[12] Energy Analects, vol. 17, no. 34, August 29, 1988

[13] Ottawa Citizen, October 27, 1988, p. C21.

[14] NB Power, Annual Report, 1986/87, p. 10.

B.8 NOVA SCOTIA

Nova Scotia, one of Canada's oldest provinces, was the first province to use hydroelectricity and is now vigorously pursuing an expanded role for electric power within the province. With 90 percent of its electricity being generated by fossil fuels, however, Nova Scotia is also concerned with the environmental implications of electric power and is currently exploring the potential use of cleaner and more efficient technologies for the burning of fossil fuels as well as alternatives to coal and oil.

B.8.1 Industrial Structure

Over one hundred electrical utilities have operated in the province of Nova Scotia over the years. Some had limited success, some failed totally, but most eventually integrated to form larger and stronger companies. One such company, Nova Scotia Light and Power, dominated the supply and distribution of electric power in the province prior to the nationalization of the industry in the early 1970s. In 1972, the shares of Nova Scotia Power were purchased by the newly created Nova Scotia Power Corporation (NSPC) which became the sole electrical utility serving the entire province.

The NSPC, which accounts for 98 percent of all electricity generated in the province,[1] relies largely on thermal generation facilities. It also owns and operates many small hydro stations throughout the province and purchases power from the New Brunswick Electric Power Commission. The NSPC serves over 373,000 customers.

Since 1976, the Nova Scotia Board of Commissioners of Public Utilities, in accordance with the provincial Public Utilities Act, has had full decision-making power over NSPCs rates and regulations. The Board's authority extends to the construction of new facilities, requiring that the utility apply directly to the Board when planning new generation or transmission facilities. As part of the review process, the Board holds public hearings during which the utility presents its proposed project, costs and alternative plans. While members of the public may intervene directly in the hearings, the Board of Commissioners has final authority over the new facilities.

B.8.2 Supply/Demand Balance

In 1987, the total installed electrical generating capacity in the province of Nova Scotia was 2346 MW. With an available capacity of 2019 MW, Nova Scotia satisfied its peak demand of 1445 MW with a reserve margin of 40 percent (see Table B.1).

TABLE B.1

ELECTRICAL GENERATING CAPACITY AND RESERVE
NOVA SCOTIA
1987

Installed Capacity	2346 MW
Available Capacity[a]	2019 MW
Peak Demand	1445 MW
Reserve Capacity	547 MW
Reserve Ratio[b]	40 %
Load Factor[c]	65 %

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a] Differences between installed and available generating capacity may be caused by a number of factors. These include the water levels in the reservoirs, the fact that not all equipment can be placed on line at the same time, and the fact that some equipment may be out of service for some reason.

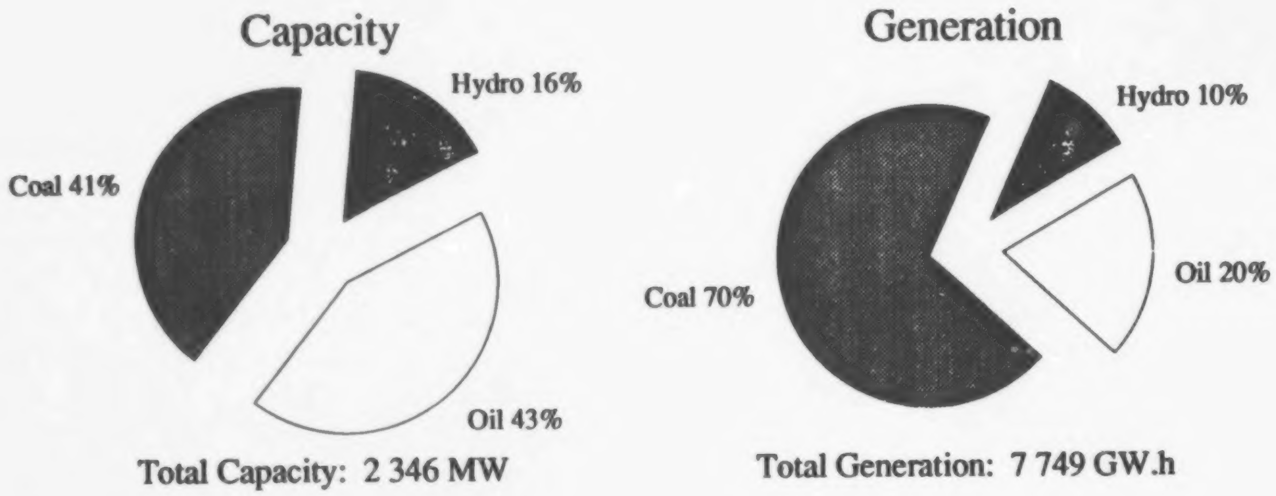
[b] Reserve ratio is defined as the reserve capacity divided by peak demand.

[c] Load factor is defined as the ratio of average load during some designated time period to maximum load during the same time period.

As indicated by Figure B.1, coal and oil comprised 41 percent and 43 percent of total generating capacity in 1987, with hydro accounting for the remaining 16 percent. Coal holds a much more dominant role in terms of electricity generation, accounting for 70 percent of total output, with the Lingan plant supplying the majority of the province's total output. Oil and hydro contributed 20 percent and 10 percent, respectively, to total generation.

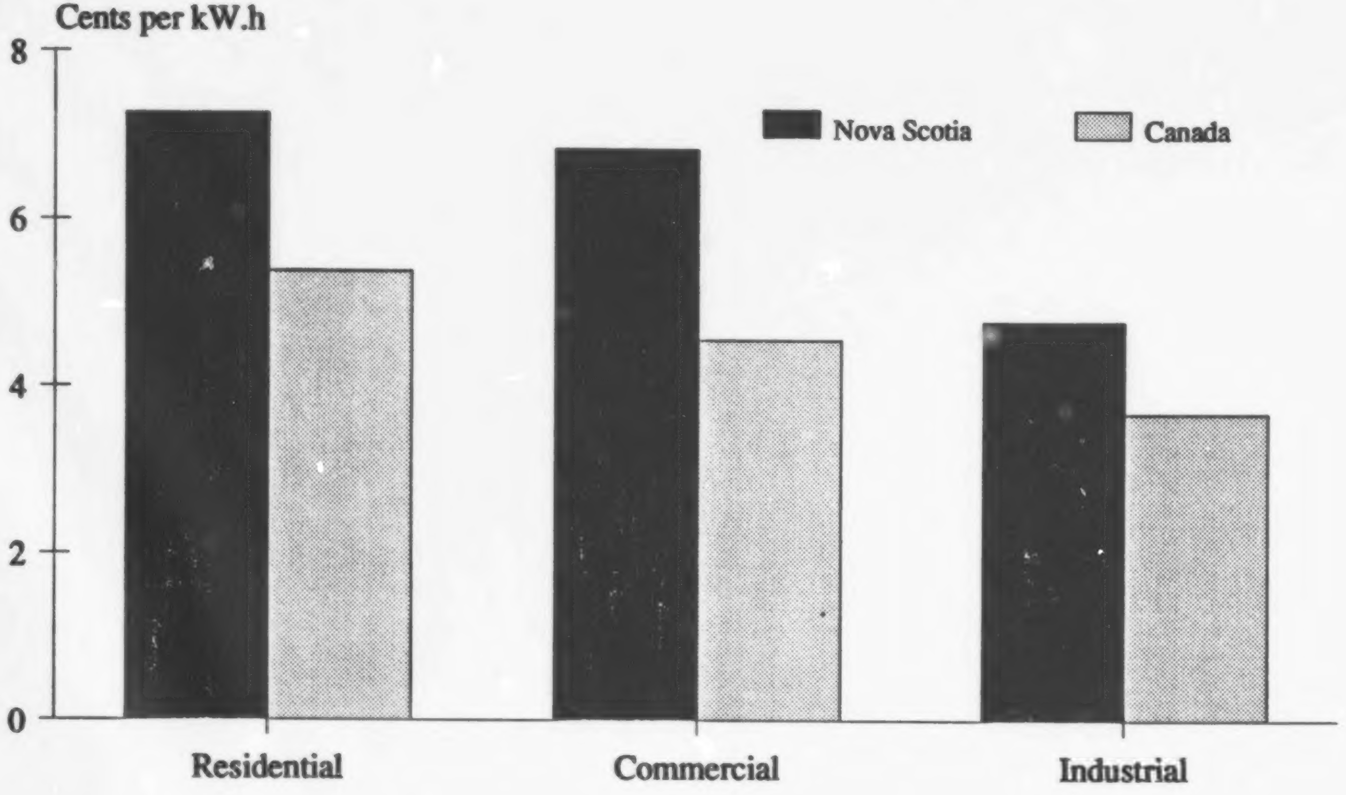
Nova Scotia has one of the lowest levels of electricity demand per capita of any province in the country--indeed, historically, only consumption rates in Prince Edward Island have been lower. The relatively high electricity rates which prevail in Nova Scotia probably explain much of this result. As indicated in Figure B.2, the province's power rates are significantly higher than the national average across

Figure B.1
Nova Scotia Electricity Supply
1987



SOURCE: EMR, Electric Power in Canada, 1987.

Figure B.2
Electricity Prices in Nova Scotia
1987



SOURCE: EMR Canada, Energy Statistics Handbook.

all demand sectors. The residential and commercial sectors account for 36 percent and 27 percent of total electricity consumption, respectively, while the industrial sector accounts for 30 percent of total electricity demand (see Figure B.3).

B.8.3 Electricity Trade

Nova Scotia's geographical location limits access to adjacent systems for trade purposes. Indeed, its only land border is with the province of New Brunswick--the only province with which trade presently occurs. Nova Scotia purchases somewhat over 660 GW.h of interruptible energy from New Brunswick, while the latter buys approximately 82 GW.h of interruptible power from Nova Scotia.[2]

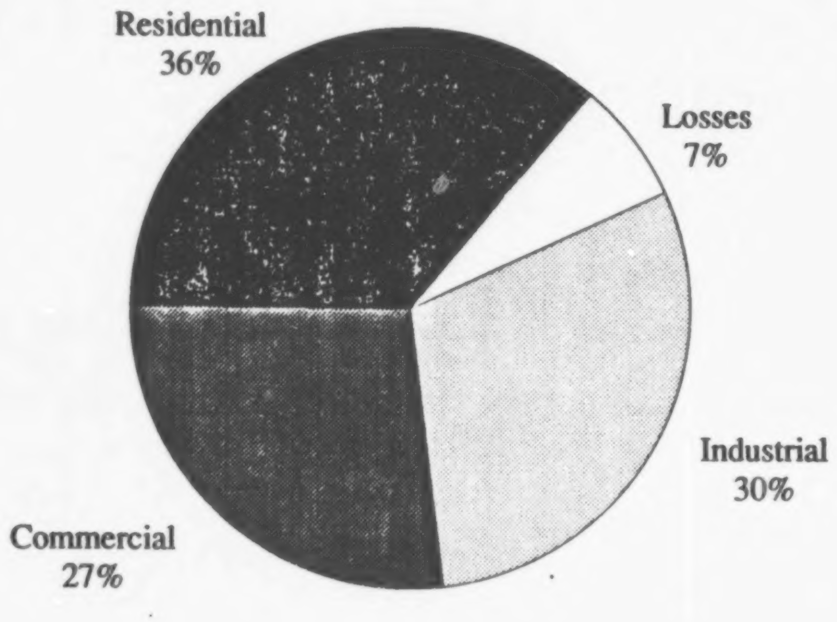
While Nova Scotia's existing trade in electricity is modest in comparison to most other provinces, the feasibility of exporting a significant amount of electricity to New England markets is currently under consideration. The provincial government has announced preliminary plans to export 900 to 1200 MW by the year 2000.

B.8.4 Emerging Issues

Nova Scotia is currently looking at various types of alternative generation projects. The objective of this exercise is to identify any projects that would diminish its dependence on oil, reduce its acid rain emissions, and enable the province to meet increasing demand while enhancing employment opportunities. Perhaps the single most important goal of the NSPC, as identified in their recent Annual Report, is to pursue plans to export electricity generated with Nova Scotia coal to the New England States.

As mentioned earlier, the Nova Scotia government has announced plans to export up to 1200 MW of power to the New England states. Following this announcement, NSPC undertook, in cooperation with Boston Edison, a study to assess the feasibility of building four thermal power generating plants to produce the needed electricity. The preliminary results from the "Bluenose Project" study show that a block of 300 MW could be exported to the New England states, starting as early as 1996, for a period of 20 years. As each of the new generating stations entered into service, NSPC would increase the quantity exported to reach 1200 MW by the year 2000. The utility has identified Sheet Harbour as the most likely site for the coal-fired units. The project is estimated to cost $4.4 billion (current dollars).

Figure B.3
Nova Scotia Electricity Demand
1987



Total Consumption: 8 327.8 GW.h

SOURCE: Statistics Canada, Quarterly Report on Energy Supply and Demand 1987-IV, (Cat. 57-203).

The next step is to have the project endorsed by the New England Power Pool (NEPOOL), by having its members take equity positions in the project. The project is currently in NEPOOL's agenda for possible transmission study in 1989.

In May of 1988, Nova Scotia Energy Minister, Ken Streach, announced a new energy policy that would allow independent power producers to participate in the generation of electric power in the province. Under the new policy, NSPC would buy up to 30 MW from private producers. The policy also stated that the energy had to be produced using Nova Scotia resources such as woodchips, hydro and waste products, rather than imported fuels.

The Nova Scotia Board of Commissioners of Public Utilities will establish the price to be paid and conditions for delivery. NSPC has submitted a proposal to the Board, which calls for the utility to sign a contract with private producers and pay them an avoided price for the power, taking into account maintenance and startup costs. The Board has yet to render a decision on the pricing formula, and public hearings on the subject will take place in the new year.[3]

Given Nova Scotia's heavy reliance on the use of coal-fired generation, concerns over acid rain and other environmental implications from the burning of fossil fuels will likely emerge as the important issues of the next decade. In this context, it is worth noting that NSPC has recently developed an environmental assessment process to identify and address all issues at the start of a project, rather than mitigate when problems appear after an operation starts.[4]

On a more concrete level, NSPC is planning to build a 150-MW fluidized bed (CFB) coal-fired generating facility in Cape Breton. The CFB technology, which uses limestone in combination with high-sulphur coal, is a way of producing electricity from coal with a minimum of environmental damage. Energy, Mines and Resources Canada has already funded a $500,000 feasibility study of a commercial-scale CFB unit in the province.

Footnotes

[1] Private generating capacity in the province includes Nova Scotia Forest Industries (27 560 kW), Minas Basin Pulp and Power (3000 kW), Scott Maritime's Pulp Ltd. (18 750 kW) and Bowaters Mersey Paper Ltd. (600 kW).

[2] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), Table A-5.

[3] Following the announcement of the new purchasing policy, Nova Scotia independent power producers formed the Small Private Power Association of Nova Scotia (SPPANS). The association is looking into the feasibility of constructing a 10-MW plant in the Digby area and a 2.3-MW plant in the Antigonish area. Both plants would burn waste wood products and woodchips. The Digby station could be operating by the summer of 1990.

[4] NSPC Sixty-Seventh Annual Report 1986/1987.

B.9 PRINCE EDWARD ISLAND

Prince Edward Island, which was entirely self-sufficient in electric power just 15 years ago, today satisfies almost all of its electricity needs from electric energy generated in the province of New Brunswick. While the cost of electricity from New Brunswick is less than the cost of electricity generated within the province, electricity rates on the Island are still as much as twice those of neighbouring Maritime provinces. This may explain, to a large extent, why residents on the Island have the lowest per capita electricity consumption of any Canadian province.

B.9.1 Industrial Structure

Prince Edward Island is serviced by two electric utilities. The major utility is Maritime Electric Company Limited (MECL), a privately-owned, integrated utility that has operated on the Island since 1918. MECL, which owns about 90 percent of the total generating capacity on the Island--including two oil-fired stations and a 10 percent share in the generation capacity of a 200-MW, oil-fired unit (No. 2) at Dalhousie in New Brunswick--provides power to the majority of consumers in Prince Edward Island. The second utility is owned by the town of Summerside, which owns its own generating facilities and distributes electricity to the local residents.[1] The Summerside utility, however, purchases the majority (over 99 percent in 1987) of the electricity it needs from MECL through the provisions of a direct customer agreement.

Because MECL's facilities on the Island are made up of relatively small, inefficient and high-cost generating plants, Prince Edward Island has looked to other provinces to meet its day-to-day electricity requirements, reserving "on-Island" capacity for mainly stand-by and peaking purposes. Indeed, the bulk of power required by MECL is obtained from New Brunswick--either in the form of direct purchases from New Brunswick Power (NB Power) or from its 10 percent share in NB Power's No. 2 Dalhousie unit.

Under the terms of the Dalhousie Ownership Participation Agreement, the energy output from the Dalhousie plant that is made available to MECL is directly contingent on the operation of the Point Lepreau Nuclear Plant. In the event of a forced outage at Point

Lepreau in excess of 28 days (other than its scheduled annual preventative maintenance outage period), MECL's entitlement to power and energy from the Dalhousie Plant will be reduced in proportion to the reduction in the net capacity of the Point Lepreau unit.

MECL activities are regulated by the Public Utilities Commission of Prince Edward Island under the Electric Power and Telephone Act. The Commission sets provincial rates and reviews all proposals for power station and transmission projects.

B.9.2 Supply/Demand Balance

Total electricity demand in the province of Prince Edward Island was 647 GW.h in 1987, 4 percent greater than in 1986. Indeed, average annual growth rates in electricity consumption have averaged around 4 percent over the last 15 years on the Island. According to the most recent National Energy Board forecasts, however, electricity consumption within the province is expected to grow at a more modest average annual rate of 2.4 percent over the 1987 to 2005 period (see Table B.1).

A sectoral breakdown of electricity demand is provided in Figure B.1. As indicated, electricity demand on the Island is dominated by the residential and commercial sectors, which account for 43 percent and 40 percent of total electricity demand, respectively. The industrial sector is of smaller importance, accounting for less than 10 percent of total demand.

As mentioned at the outset, the source of Prince Edward Islands electricity supply has shifted from on-Island generation to purchases from the province of New Brunswick. The path of this transition is charted in Figure B.2. While on-Island generation accounted for all of Prince Edward Island's electricity needs as recently as 1976, by 1979 the dominant source of power was imports from New Brunswick. These purchases from NB Power, combined with electricity generated from MECL's equity share in the No.2 Dalhousie unit, now supply the vast majority (90 percent) of the Island's electricity needs. In addition, Prince Edward Island, Quebec and New Brunswick have recently signed an agreement to provide the Island with 50 MW of firm power until 1994. Under the terms of the agreement, New Brunswick will buy the power from the province of Quebec and resell it to Prince Edward Island at a price which is sufficient to cover the costs of carrying the electricity to the Island.

While "on-Island" generation currently supplies less than 10 percent of total electricity demand in the province, MECL must maintain a sizeable generating capacity within the province (102 MW) for several reasons. First and most importantly, only 25 percent of electricity imports from the province of New Brunswick can be classified as firm. The remainder may be suspended upon 12 months notice.[2] Secondly, these imports as well as electricity supplied to the province by MECL's equity interest in facilities in New Brunswick are transmitted to the Island by way of one of two 138-kV submarine cables with a maximum capacity of 100 MW each. Since the peak load of the province is approximately 110 MW, generating facilities on the Island must be operated for short intervals during the year. Moreover, since in New Brunswick the cable is served by only one overhead line for the 25 miles between Memramcook and Murray Corner, the total interconnection cannot be considered completely secure. Under these circumstances, it is critical that sizeable generating facilities on the Island be maintained.

TABLE B.1

ELECTRICAL GENERATING CAPACITY AND RESERVE
PRINCE EDWARD ISLAND
1987

Installed Capacity	122 MW
Available Capacity[a]	140 MW
Peak Demand	91 MW
Reserve Capacity	49 MW
Reserve Ratio[b]	54 %
Load Factor[c]	81 %

SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a] Differences between installed and available generating capacity may be caused by a number of factors. These include the fact that not all equipment can be placed on line at the same time, and the fact that some equipment may be out of service for some reason.

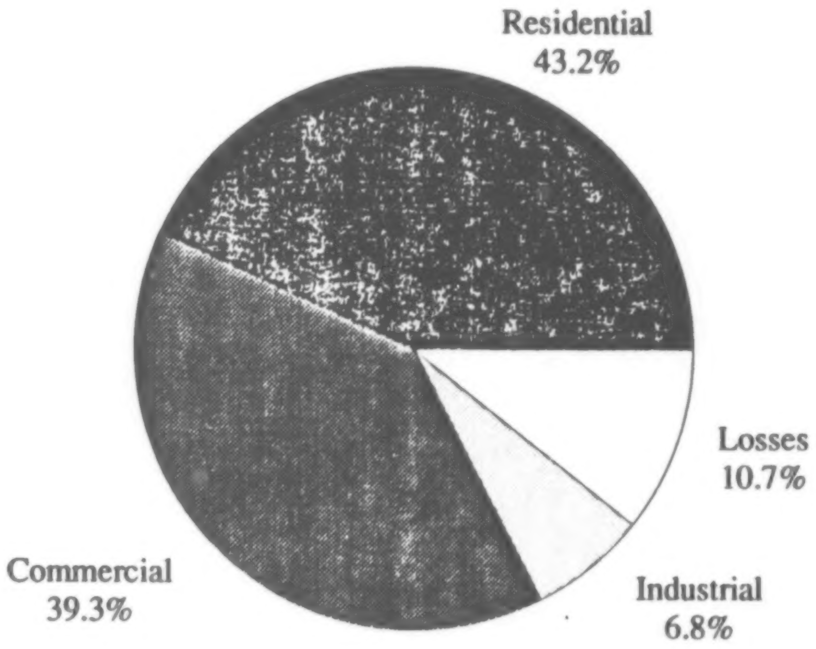
[b] Reserve ratio is defined as the reserve capacity divided by peak demand.

[c] Load factor is defined as the ratio of average load during some designated time period to maximum load during the same time period.

B.9.3 Emerging Issues

As indicated by Figure B.3, Prince Edward Island's electricity rates are well above the national average. Certainly a contributing

Figure B.1
Prince Edward Island Electricity Demand
1987

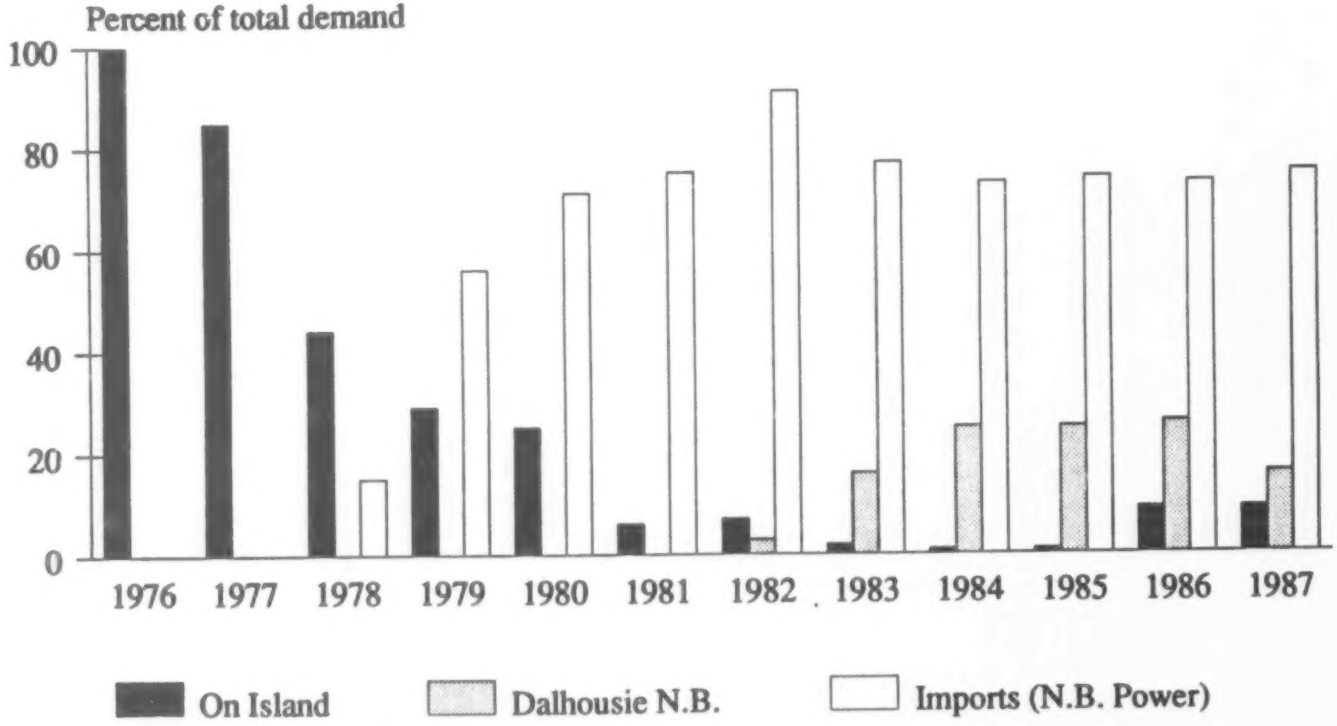


Total Consumption: 648.7 GW.h

SOURCE: Statistics Canada, Quarterly Report on Energy Supply and Demand 1987-IV (Cat.57-003).

Figure B.2

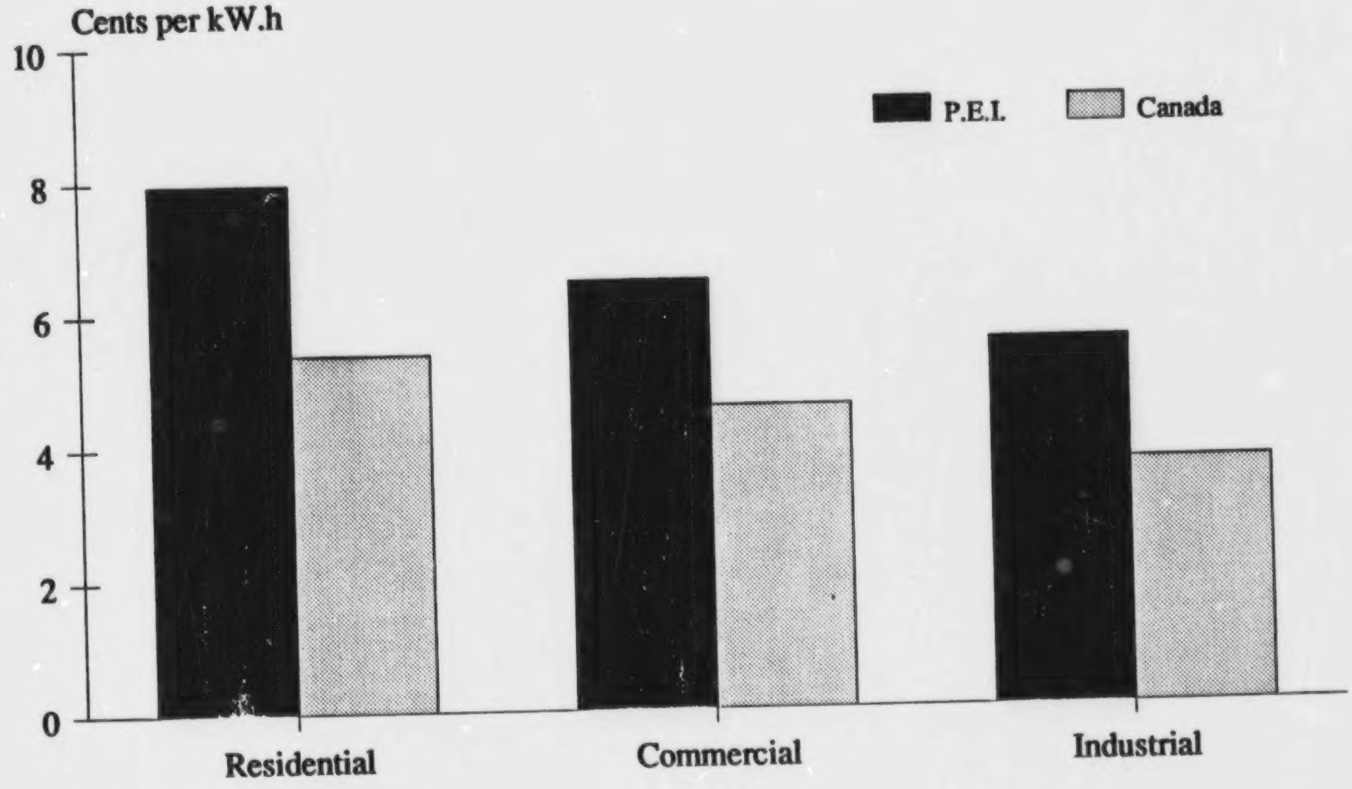
Sources of Electricity Generation in Prince Edward Island (1976 - 1987)



SOURCE: Prince Edward Island Electricity Report, 1986 and EMR, Electric Power in Canada, 1987.

Figure B.3

Electricity Prices in Prince Edward Island - 1987



SOURCE: EMR Canada, Energy Statistics Handbook.

factor is the fact that while MECL obtains almost all of its required electricity from NB Power, it must at the same time maintain a significant generating capacity on the Island. These measures are prudent in light of the nature of the existing interconnection facilities.

The capacity of the existing interconnection with New Brunswick would be sufficient to handle the Island's energy requirements for some time into the future provided that both submarine cables which link the Island with New Brunswick could be operated simultaneously. This is not currently the case. Only one cable can operate at any given time, with the second cable serving as a backup. Furthermore, roughly 3 to 4 hours is needed to switch from one cable to another during which time on-Island generation is essential.

A number of studies, carried out for both MECL and the province, have confirmed that there is a definite need for a secure, reliable and flexible interconnection between Prince Edward Island and New Brunswick. Negotiations between NB Power and MECL to upgrade the interconnection are now in progress. These negotiations include strengthening of the overhead transmission system in New Brunswick as well as upgrading the submarine cable.[3]

The actions taken to strengthen the Prince Edward Island-New Brunswick interconnection are part of a broader five-part development plan which the province has adopted. The plan calls for: (i) the purchase of power and energy from New Brunswick to meet the Island's energy requirements until 1994; (ii) long-term equity participation in a non-oil-fired generating unit in New Brunswick, Nova Scotia, or Quebec; (iii) upgrading of the P.E.I./New Brunswick underwater cable interconnection; (iv) the construction of two wood-fired power plants on the Island; and (v) the implementation of a conservation and load management program.

The first step in this plan has now been taken. On July 27th 1988, NB Power and P.E.I. reached an agreement which calls for: (i) NB Power to sell 50 MW of capacity and energy to P.E.I., on specified terms, until 1994; and (ii) Hydro-Quebec to sell 50 MW of capacity to NB Power over the same period. These agreements were formally signed by the three Premiers in Charlottetown on August 25, 1988. The second step will involve the purchase of 50 MW of generation from Nova Scotia, New Brunswick or Quebec. These alternatives are currently under examination by the province.

Regarding the third step, on October 6, 1988, Prince Edward Island made a formal proposal to the Minister of Energy Mines and Resources Canada, which calls for federal assistance for the upgrading of the Prince Edward Island-New Brunswick underwater cable interconnection, at an estimated capital cost of $9.6 million.

Footnotes

[1] Summerside's generating capacity is used exclusively for stand-by power for its own system.

[2] The interconnection agreement does state, however, that the parties will make available to each other, in case of emergency, generating capacity up to the limit of the capabilities of the interconnection facilities.

[3] Also included is the upgrading of the switching facilities at both Murray Corner, New Brunswick, and Richmond Cove, P.E.I., to permit both cables to be used simultaneously and, in case of outage, to allow immediate switching from one cable to another.

B.10 NEWFOUNDLAND

Newfoundland is the third-largest producer of hydroelectricity in Canada, after Quebec and British Columbia. This is a bittersweet distinction for the province, however, because almost 90 percent of Newfoundland's hydroelectric energy is produced by a single generating station--the massive Churchill Falls development in Labrador.[1] In turn, the bulk of Churchill Falls production is sold to Hydro-Quebec at roughly 0.3 cents per kW.h, under a long-term contract signed by the two provinces before the energy price shocks of the 1970s. The Newfoundland government tried to have this contract revised in a lengthy court battle that reached the Supreme Court of Canada, which ultimately decided against Newfoundland. Newfoundland and Labrador Hydro, the provincial utility, now wishes to develop the Lower Churchill and other hydroelectric resources in Labrador, if a mutually acceptable agreement can be reached with Quebec to wheel the subsequent power to markets in Ontario and/or the United States. On the island of Newfoundland, the development of much smaller hydroelectric sites over the past three decades has helped to greatly reduce the province's dependence on imported oil as an energy source.

B.10.1 Industrial Structure

There are two major electric utilities in Newfoundland: the provincially-owned Newfoundland and Labrador Hydro, and the investor-owned Newfoundland Light and Power Co. The bulk of final retail sales of electricity within Newfoundland are handled by Newfoundland Light and Power, while Newfoundland and Labrador Power is responsible for most of the province's generation.

The provincial government created the Newfoundland Power Commission in 1954 to develop some of the province's remaining hydroelectric sites. Ten years later, the Commission began construction of the Bay d'Espoir hydro generating station, which at 600 MW is still the largest power station on the island of Newfoundland. Energy produced by this and three other hydroelectric developments was supplemented by the construction of oil-fired thermal plants and smaller diesel generators in isolated areas. In 1974, the Newfoundland government purchased Brinco's share in the just-completed Churchill Falls megaproject, and this interest was merged with the Newfoundland Power Commission to form what is now known as Newfoundland and Labrador Hydro.

Newfoundland and Labrador Hydro controls a number of subsidiary firms. Most prominent among these is the Churchill Falls (Labrador) Corporation, which owns and manages the Churchill Falls station; Hydro-Quebec still owns a minority share of this subsidiary. Other subsidiaries include the Twin Falls Power Corp., the Gull Island Power Co., and the Power Distribution District of Newfoundland and Labrador (a corporate entity responsible for the promotion of rural electrification in the province). The provincial utility owns a 51 percent share in a fifth subsidiary, the Lower Churchill Development Corporation, which is investigating the possibility of further hydroelectric developments on the Churchill River; the other 49 percent is owned by the federal government.

Newfoundland and Labrador Hydro is managed by a 7-person Board of Directors, appointed by the provincial government. All construction projects must receive approval of the provincial Cabinet. The company's residential electricity rates can be examined by the Newfoundland Board of Commissioners of Public Utilities, but the provincial cabinet again has final authority in this area.

The Newfoundland Light and Power Company was incorporated in 1966 as the result of an amalgamation among several private utilities on the island. One of these founding utilities, the St. John's Electric Light Co., began operations in the St. John's area in 1885. While the company is responsible for the direct servicing of most retail customers in Newfoundland, it is responsible for only a small share of electricity production--less than 5 percent of provincial generation in 1987, excluding Churchill Falls--produced by its own hydroelectric plants.[2] About 90 percent of the company's electricity supply is purchased in bulk from Newfoundland and Labrador Hydro.

Newfoundland Light and Power is also regulated by the province's Board of Commissioners of Public Utilities, but this agency's authority is much stronger with the private utility than it is with Newfoundland and Labrador Hydro. Rate changes and the construction of new facilities are subject to the approval of the Board. Construction projects of both major utilities are also subject to the final approval of Cabinet under the terms of the Environmental Assessment Act, if the Minister of the Environment decides that the project warrants an environmental impact study.

There are a number of other small privately-owned utilities operating in Newfoundland, the largest of which is the Deer Lake Power Co. Ltd., based in the western area of the island of Newfoundland. A small amount of electricity--about one percent of the provincial total in 1987--is produced by industrial firms which own their own generating equipment.

B.10.2 Current Supply/Demand Balance

Total installed generating capacity in Newfoundland in 1987 was approximately 7400 MW, the largest of any of the Atlantic Provinces, and the fifth largest in Canada (see Table B.1, Figure B.1). Available capacity, however, is much lower, since all but 300 MW of the Churchill Falls station is dedicated to the export of firm power to Quebec. When the committed Churchill Falls capacity is deducted, a net total of just under 2100 MW of generating capacity is left for the supply of electricity to consumers within Newfoundland. Peak demand in the province reached 1674 MW in 1987, leaving about 400 MW of spare capacity.

TABLE B.1

INTEGRATED NEWFOUNDLAND SYSTEM CAPACITY AND RESERVE, 1987

Installed Capacity[a]	7402 MW
Available Capacity[b]	2072 MW
Peak Demand[c]	1674 MW
Reserve Capacity	398 MW
Reserve Ratio	23.8 %
Load Factor[d]	66.1 %

SOURCES: (1) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (2) response of utilities to Energy, Mines and Resources Electricity Branch questionnaire.

[a] Includes Churchill Falls and other Labrador facilities.

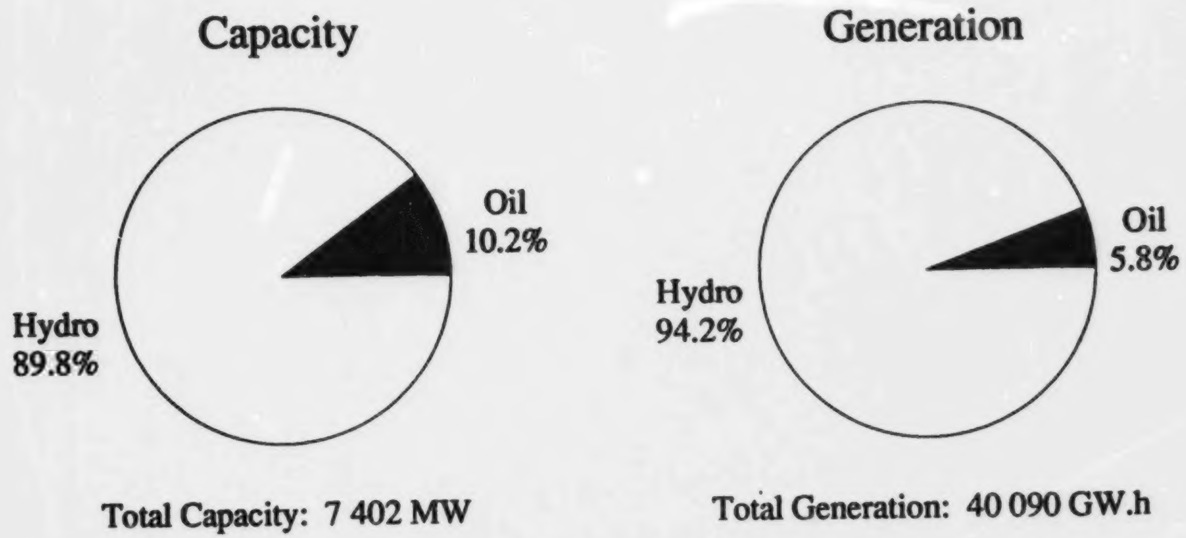
[b] Island of Newfoundland; NLH and NLPC facilities only.

[c] Equals combined peak demands of NLH and NLPC less NLPC generating capacity.

[d] Average hourly energy sales as a share of annual peak demand; includes Labrador.

Thanks primarily to the giant Churchill Falls development, hydroelectric plants account for the lion's share of total generating capacity in Newfoundland (see Table B.2). If the Churchill Falls plant is excluded, then hydroelectricity provides only 65 percent of

Figure B.1
Newfoundland Electricity Supply
1987



SOURCE: EMR, Electric Power in Canada.

Includes Churchill Falls; hydro's share of total excluding Churchill Falls is 61.6% of capacity & 76.1% of generation.

Newfoundland's electricity production, from about 62 percent of its total generating capacity. The remainder of Newfoundland's electricity is produced in oil-fired thermal facilities, the largest of which is located at Holyrood, near St. John's. This facility consumed over 3.5 million barrels of residual fuel oil in 1987 (an average of almost 10,000 barrels per day). In total, electricity generation was responsible for about one-quarter of Newfoundland's petroleum consumption in 1987.[3]

TABLE B.2

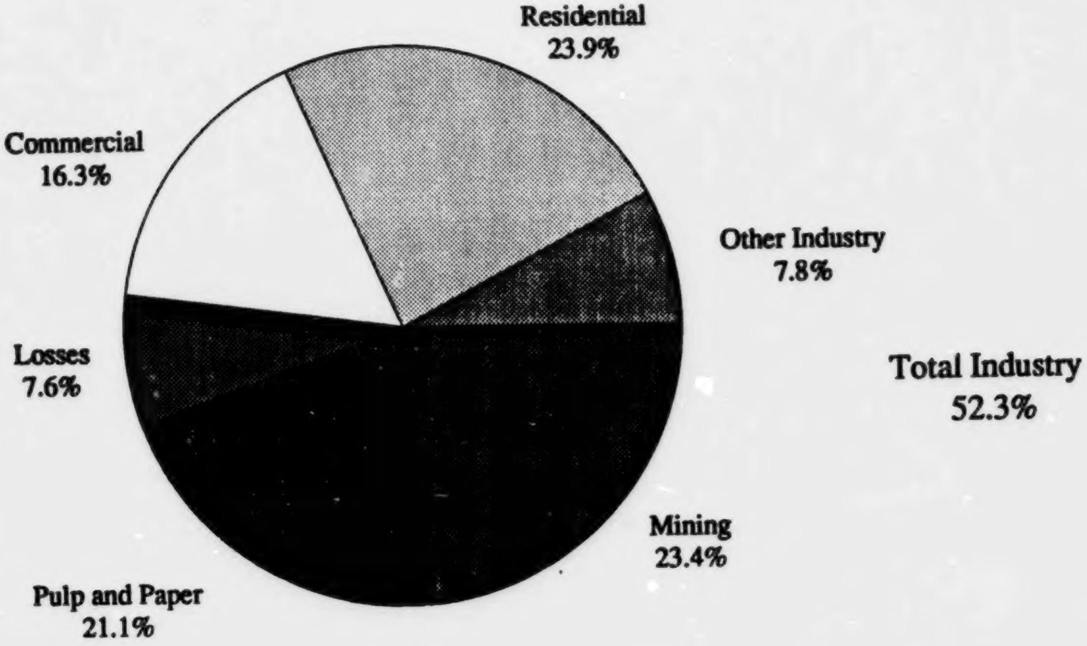
NEWFOUNDLAND AND LABRADOR HYDRO MAJOR DEVELOPMENT PROJECTS

Projects	Capacity	Year in Service
Committed Projects		
Roddickton (Woodchips)	5 MW	1988
Holyrood Expansion (Oil-Fired)	50 MW	1989
Paradise River (Hydro)	8 MW	1989
Stephenville (Oil-Fired Gas Turbine)	54 MW	1990
Hardwood (Oil-Fired Gas Turbine)	54 MW	1990
Future Projects		
Gull Island (Hydro)	1698 MW	
Muskrat Falls (Hydro)	618 MW	
Churchill Falls #12 (Hydro)	495 MW	
Island Pond (Hydro)	30 MW	
Round Pond (Hydro)	18 MW	
Granite Canal (Hydro)	31 MW	
Oil-Fired Gas Turbine (location undecided)	54 MW	

SOURCES: (1) Newfoundland and Labrador Hydro, Annual Report, 1987; (2) Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988); and (3) press reports.

Newfoundland's per capita consumption of electricity is almost exactly equal to the Canadian average, at some 16 745 kilowatt-hours per person per year.[4] Over 50 percent of domestic electricity demand is centred in the industrial sector, particularly in the mining and pulp and paper industries (see Figure B.2). The remaining share of electricity consumption is divided amongst residential users, the commercial sector and energy losses incurred by the electricity industry itself. Provincial electricity demand declined slightly in 1987, following a modest increase of 0.5 percent in 1986.

Figure B.2
Newfoundland Electricity Demand
1987



Total Consumption: 9 861 GW.h

SOURCE: Statistics Canada Quarterly
Report on Energy Supply-Demand.

Demand growth in Newfoundland has been less than half of the national average rate experienced since 1980, primarily because the province's heavy reliance on imported oil for electricity production led to severe electricity price increases following the energy price shocks of the preceding decade. As is typical of other Atlantic provinces, Newfoundland's electricity rates are significantly higher than those experienced in the rest of the country (see Figure B.3). Rate increases since the end of 1983, however, have been relatively modest--an average of less than 3 percent per year for Newfoundland Light and Power and a total decline in average rates of 1.7 percent for Newfoundland and Labrador Hydro--reflecting the moderation in world oil prices that has been experienced in recent years.[5]

B.10.3 Electricity Trade

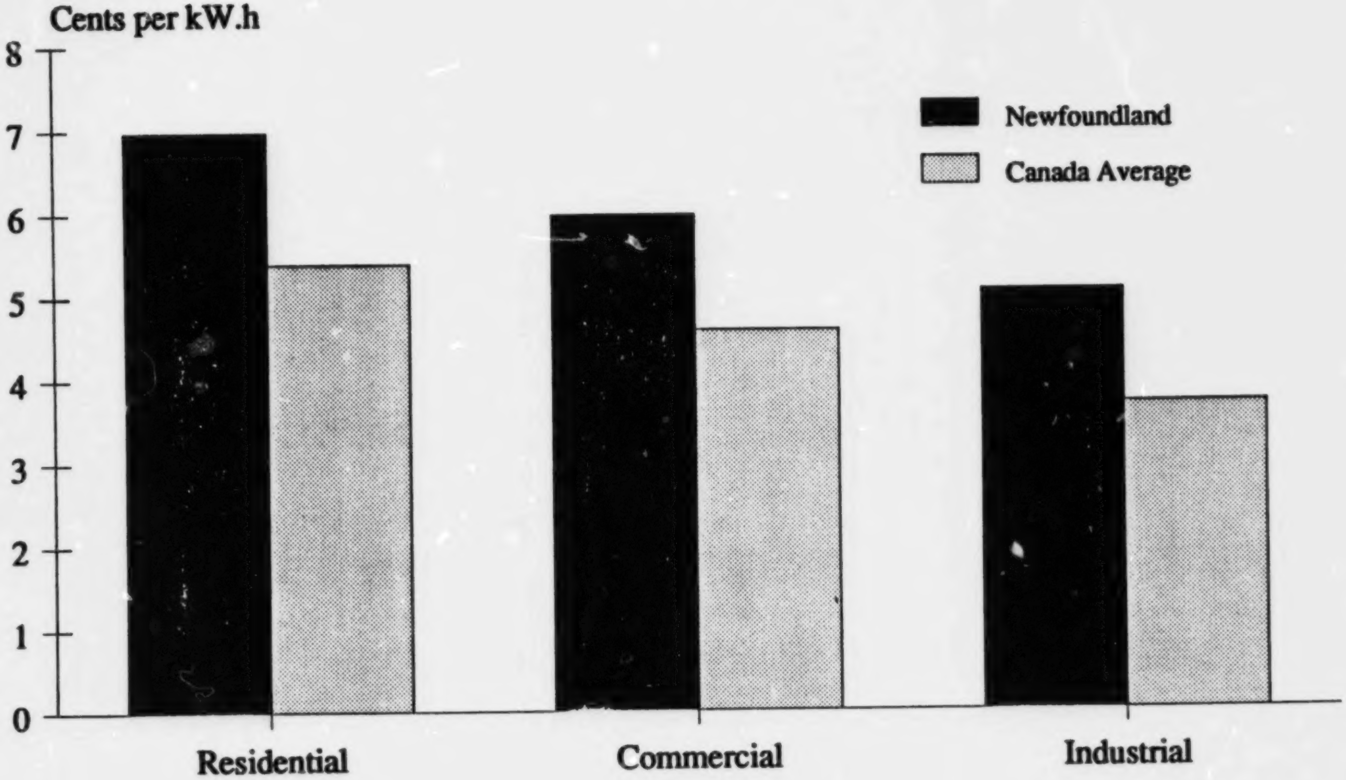
The geography of Newfoundland has placed severe restrictions on its ability to trade electricity with other provinces or with the United States. Its only common land border is shared with Quebec; therefore, all of Newfoundland's electricity trade is with Quebec. In 1987, the province sold 30 393 GW.h of firm energy from its Churchill Falls plant to Quebec,[6] representing almost two-thirds of all interprovincial electricity trade in Canada. This flow of energy was somewhat lower than in previous years, primarily because 1987 marked the fourth consecutive year of below-average water inflows into the reservoirs of the Churchill Falls system. The Churchill Falls exports to Quebec netted an average price of only 0.29 cents per kilowatt-hour, about one-fourteenth of the average revenue received by Newfoundland and Labrador Hydro for its electricity sales within Newfoundland.[7] This reflects the 65-year contract signed with Hydro-Quebec when the construction of Churchill Falls first started in the late 1960s; while this contract was necessary to justify the early construction of the project, it did not anticipate the sharp increase in the prices of electricity and other fuels that soon followed.

Newfoundland and Quebec share the highest-voltage interprovincial electricity interconnection in Canada: three 735-kV lines stretching over 1100 kilometres from Churchill Falls to Quebec City and Montreal, with a total capacity of 6000 MW.[8]

B.10.4 Emerging Issues

There is no question that power wheeling is the most important issue facing the electricity industry in Newfoundland. Following the province's unsuccessful court challenge to the validity of the

Figure B.3
Newfoundland Electricity Prices
1987



SOURCE: EMR Canada, Energy Statistics Handbook.

Note: Assumes monthly bills of 1 000 kW.h residential; 300 000 kW.h commercial; 1.3 million kW.h industrial.

Churchill Falls sales contract, planners with Newfoundland and Labrador Hydro have now turned their attention to the future and hopefully more profitable development of other hydroelectric resources in Labrador. These potential resources are significant, and account for a large majority of the total estimated undeveloped hydroelectric capacity in Newfoundland of some 4600 MW.[9] The two largest Labrador sites for development (Gull Island and Muskrat Falls, both located on the Lower Churchill) have potential capacities of 1700 MW and 600 MW, respectively. While considerably smaller than the energy production of Churchill Falls, they would nevertheless result in a substantial increase in Newfoundland's total installed generating capability.

Holding back the development of these projects is the lack of successful negotiation regarding a development agreement with Quebec. Labrador itself consumes an insufficient volume of electrical energy--less than 600 GW.h in 1987, three-quarters of this by industrial consumers--to justify any major new developments.[10] It is possible that Labrador's power could be delivered to the island of Newfoundland, via an expensive 1000-kilometre transmission line (including an underwater crossing of the Strait of Belle Isle). More appealing, in the medium term, is the possibility of wheeling the power of the Labrador developments to the lucrative export markets of the northeastern United States, or possibly to Ontario. This would require the cooperation of Hydro-Quebec and the Quebec government. Discussions between the two provinces concerning the development of both Gull Island and Muskrat Falls, as well as possibly adding a twelfth generating unit (producing more than 500 MW) to the existing Churchill Falls development, are being held.[11] The electricity produced by these projects would be delivered in part to the island of Newfoundland, and in part to Quebec for subsequent resale to export markets or to Ontario.

In the meantime, a number of marginal additions to the existing network have been rescheduled due to the recent closure of the Long Harbour phosphorous plant in Placentia Bay. This closing will allow Newfoundland and Labrador Hydro to recapture roughly 100 MW of power, and thereby postpone making any decisions on future development plans for as long as 2 years.

Footnotes

[1] Newfoundland and Labrador Hydro, Annual Report, 1987, p. 15.

[2] Ibid., pp. 18-19.

[3] Statistics Canada, Quarterly Report on Energy Supply-Demand in Canada, Catalogue No. 57-003 (Ottawa, Ontario: Minister of Supply and Services Canada).

[4] Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988), p. 23.

[5] Ibid., p. 65.

[6] Ibid., p. 49.

[7] Newfoundland and Labrador Hydro, Annual Report, 1987, p. 29.

[8] Energy, Mines and Resources Canada, Electric Power in Canada: 1987, p. 54.

[9] Ibid., p. 83.

[10] Newfoundland and Labrador Hydro, Annual Report, 1987, p. 5.

[11] The Evening Telegram, November 28, 1988, p. 1.

B.11 THE YUKON AND NORTHWEST TERRITORIES

The unusual geographic and demographic characteristics of the Yukon and Northwest Territories pose particular difficulties for the supply of electric power in these regions. The Territories represent less than 0.3 percent of the total Canadian population but occupy 3.8 million square kilometres, or about 38 percent of the total area of Canada. Due to the correspondingly low population densities, the electrical supply network is characterized by a large number of small generating stations and only a limited transmission network. These factors, along with the preponderance of diesel generation capacity in the North, result in this region having the highest electricity prices in Canada.

B.11.1 The Devolution of the NCPC

From 1956 to 1987, the Northern Canada Power Commission (NCPC)--a Crown corporation responsible to the Federal Ministry of Indian Affairs and Northern Development--was the principal agency generating and transmitting electrical energy in the Yukon and Northwest Territories. By 1987, the NCPC was operating 50 separate systems throughout the territories, serving approximately 1500 customers. In November 1985, however, the Minister of Indian Affairs and Northern Development entered into a Memorandum of Understanding with the energy ministers in both territorial governments to work towards the transfer of the NCPC to territorial ownership and control.

In March 1987, the Government of the Yukon Territory and the federal government reached an agreement to transfer the Yukon portion of the NCPC from federal to territorial control and ownership. The Yukon government has placed ownership and control of the new company--the Yukon Energy Corporation--with the Yukon Development Corporation, which has in turn entered into a 5-year management services agreement with the privately-owned Yukon Electrical Company for the management of the new utility. Under the terms of the contract, the Yukon Electrical Company will operate the Yukon Energy Corporation's assets, purchase the electricity generated, and distribute it to the Energy Corporation's customers.

The Yukon Energy Corporation, which is now the principal electrical utility in the territory, is subject to the regulations of the Yukon Utility Board, under the Public Utilities Act of 1986. Under the Act, the Corporation must file applications for rate changes or facility construction with the Board. The Board then reviews the application and makes a decision on the request. In May 1988, the federal government reached a similar agreement with the Government of the Northwest Territories, transferring the N.W.T. portion of the NCPC assets, worth $96 million, from federal to territorial control. The Government of the Northwest Territories has set up a new Crown corporation--the Northwest Territories Power Corporation (N.W.T. Power Corporation)--to assume these responsibilities. This corporation will be under the responsibility of the territorial ministry of Energy, Mines and Resources.

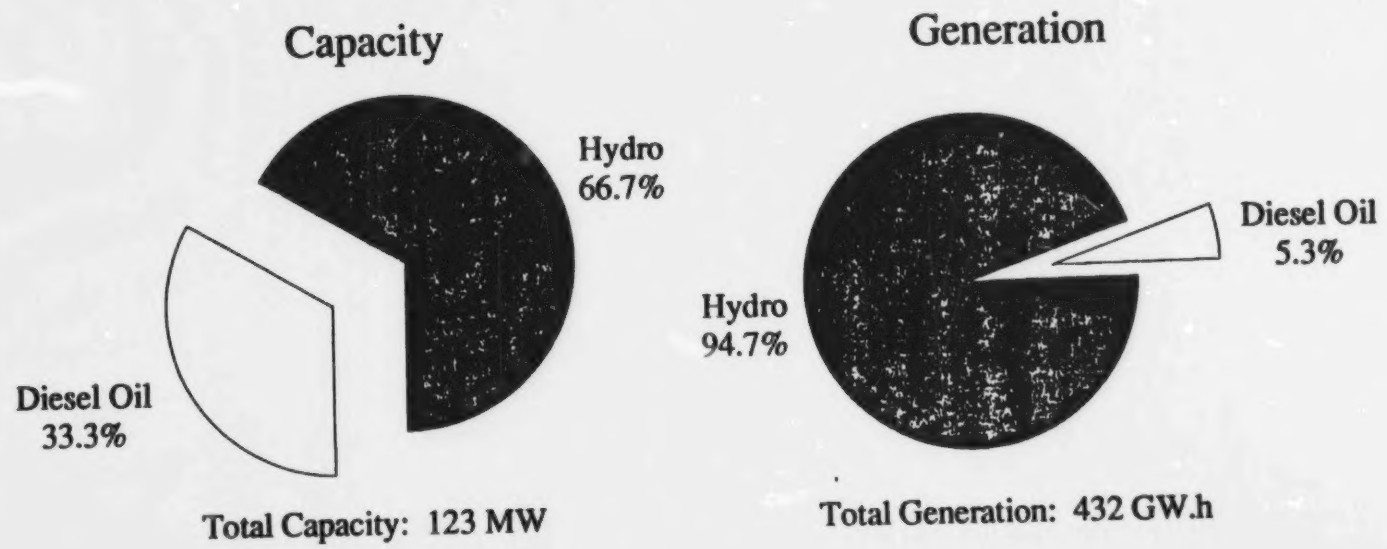
The regulation of rates and structures is currently performed by the Government of the Northwest Territories. The N.W.T. Public Utilities Board Act, however, is currently being revised and it is expected that once the revision is complete, the N.W.T. Power Corporation will be regulated by the Public Utilities Board which derives its powers from this act. The scheduled date for completion of the revision is late 1989.

B.11.2 Supply/Demand Balance: Yukon

Total installed generating capacity in the Yukon stood at 123 MW in 1987, comprised of 82 MW (66.7 percent) of hydroelectric capacity and 41 MW (33.3 percent) of oil-fired generating capacity (see Figure B.1). As indicated by Table B.1, peak demand in the same year reached only 68 MW, leaving the territory with a reserve margin of close to 78 percent--more than double the national average.[1] Total electricity generation in the Yukon Territories was 432 GW.h in 1986/1987, with 90 percent of this amount supplied by small hydro generating plants and the remainder by small oil-fired plants (see Figure B.1). The largest hydro and oil-fired generating stations in the territory have capacities of 40 MW and 20 MW, respectively.

A sectoral breakdown of total electricity demand in the Yukon is provided in Figure B.2. As shown, roughly 43 percent of total demand is accounted for by the industrial sector, while the residential and commercial sectors each account for approximately 27 percent of total electricity demand. All electricity generated in the Yukon is consumed within the territory, and there are no electricity transfers into the region.

Figure B.1
Yukon Territory Electricity Supply
1987



SOURCE: EMR, Electric Power in Canada.

TABLE B.1

ELECTRICAL GENERATING CAPACITY AND RESERVE IN THE YUKON AND NORTHWEST TERRITORIES 1987

Yukon	
Installed Capacity	123 MW
Available Capacity[a]	121 MW
Peak Demand	68 MW
Reserve Capacity	53 MW
Reserve Ratio[b]	78%
Load Factor[c]	73%
Northwest Territories	
Installed Capacity	190 MW
Available Capacity[a]	186 MW
Peak Demand	111 MW
Reserve Capacity	75 MW
Reserve Ratio[b]	68%
Load Factor[c]	48%

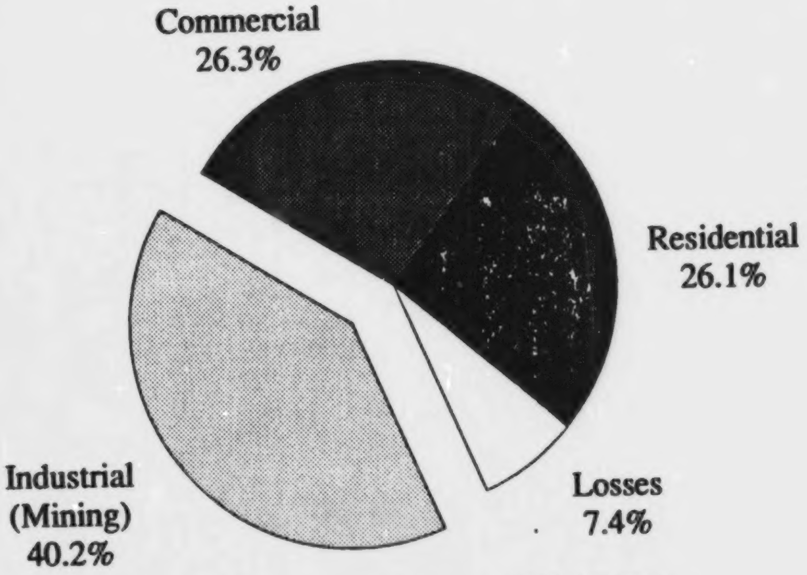
SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa: Minister of Supply and Services Canada, 1988).

[a] Differences between installed and available generating capacity may be caused by a number of factors. These include the fact that not all equipment can be placed on line at the same time, and the fact that some equipment may be out of service for some reason.

[b] Reserve ratio is defined as the reserve capacity divided by peak demand.

[c] Load factor is defined as the ratio of average load during some designated time period to maximum load during the same time period.

Figure B.2
Yukon Electricity Demand
1987



Total Consumption: 433 GW.h

SOURCE: Statistics Canada, Electric Power Statistics, vol. 3, (Cat. 57-202).

It is worth noting that historically, the production and sale of electricity in the Yukon has been strongly influenced by the economic fortunes of a handful of mining firms which account for all the industrial demand in the territory. The re-opening of the Cyprus-Anvil lead and zinc mine in Whitehorse, for example, was largely responsible for the 25 percent increase in electricity demand which occurred in the territory in 1987. More generally, it was the depressed nature of the mining sector as a whole which accounted for the below average growth rates of 1.7 percent which characterized electricity demand in the Yukon over the 1975-1987 period (see Table B.2).

TABLE B.2

GROWTH IN ELECTRICITY CONSUMPTION AND PEAK DEMAND YUKON AND THE NORTHWEST TERRITORIES - 1975-2005 AVERAGE ANNUAL GROWTH RATES (percent)

	Electricity Consumption			Peak Demand		
	1975-87	1986-87	1987-2005	1975-87	1986-87	1987-2005
Yukon	1.7	25.6	2.2	0.3	-1.5	1.9
N.W.T.	0.8	-12.7	1.1	4.2	-7.5	2.0
Canada	4.2	3.9	2.1	3.7	1.9	2.3

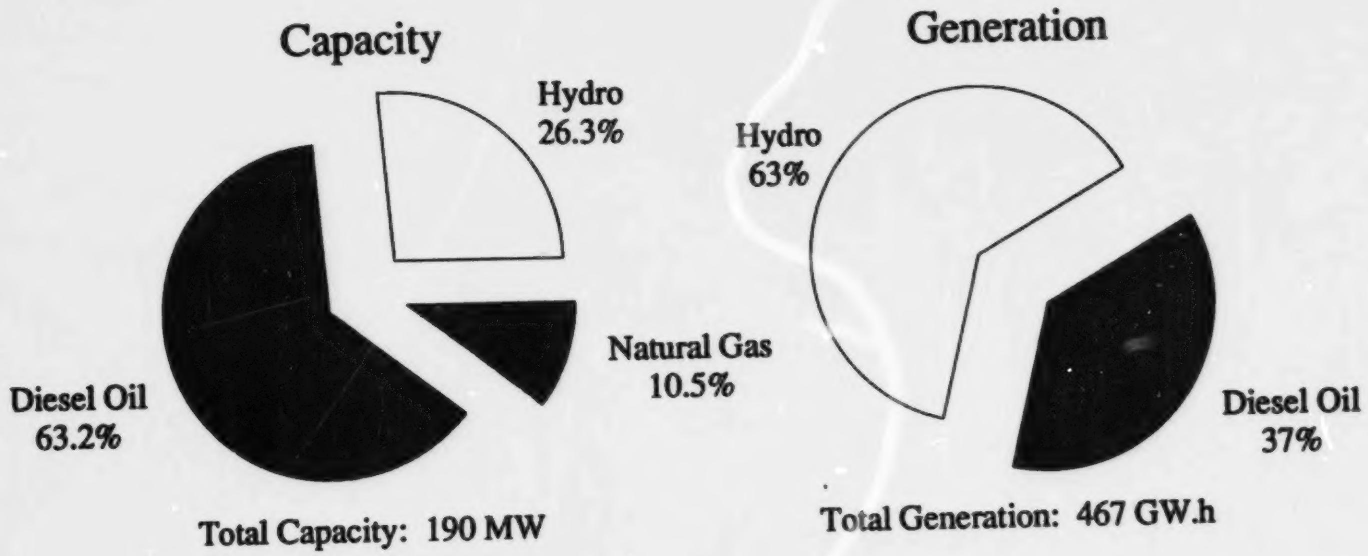
SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada: 1987 (Ottawa, Ontario: Minister of Supply and Services Canada, 1988).

World metal prices are expected to rise over the near term, leading to an increase in activity levels in the Yukon's lead, zinc and silver mines and an increase in the demand for electricity in the Yukon. Peak demand is expected to grow in the territory over the 1987-2005 period at an average annual rate of 2 percent or less. Capacity additions, though not expected to occur for some time, will likely take the form of small diesel plants, with the possible exception of a 2-MW hydro plant for the city of Dawson in the late 1990s.

B.11.3 Supply/Demand Balance: Northwest Territories

As indicated by Figure B.3, total electricity generation in the Northwest Territories was 467 GW.h in 1987, with 63 percent of this total supplied by hydro facilities and the remainder supplied by oil-fired plants. Total installed capacity in 1987 was 190 MW, all of which

Figure B.3
Northwest Territories Electricity Supply
1987



SOURCE: EMR, Electric Power in Canada.

was used to supply electricity needs within the territory. Peak demand reached 111 MW in 1987, leaving reserve capacity of 75 MW and a reserve margin of 68 percent (see Table B.1).

A sectoral breakdown of electricity demand in the territories is provided in Figure B.4. As indicated, the industrial sector accounts for 48 percent of total electricity demand, while the residential and commercial sectors account for 20 percent and 22 percent of total demand, respectively. As was the case in the Yukon, industrial demand derives entirely from the activities of the mining firms in the region, with sharp swings in the levels of economic activities within this sector accounting for equally sharp swings in electricity demand. Peak demand was down by over 7 percent in 1987 from 1986. This was largely due to a significant reduction in activity levels at the Pine Point gold mine.

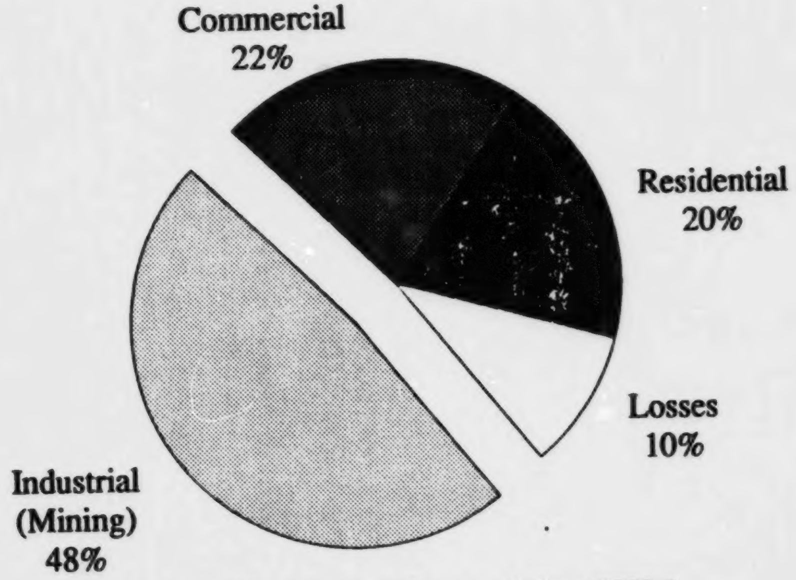
Peak demand in the Northwest Territories is expected to grow at an average annual rate of less than 2.0 percent until the year 2005. The majority of this growth will come from increased activity levels in the industrial sector, while little if any increase in electricity demand in the residential and commercial sectors is expected. It is likely that small diesel oil-fired plants will be built to meet additional capacity requirements, if and when they occur.

B.11.4 Emerging Issues

As indicated in Figure B.5, electricity prices in the Yukon and the Northwest Territories are well above the national average. Indeed, residential and commercial rates in the capital cities of Yellowknife and Whitehorse exceed the rates which prevail in all other major Canadian cities. It is not surprising, then, that the twin issues of pricing and the displacement of diesel oil with less costly generation alternatives are the most important concerns facing the electric power supply industry in the North today.

At the time of the devolution of the NCPC to territorial ownership and control, a relatively complex system of electricity prices prevailed throughout the northern Territories which included two federal subsidy programs aimed at reducing the cost of electricity to both residential and commercial consumers in remote areas of the North. To date, these subsidies continue to be reflected in the rate structures in both territories. While the future course of electricity prices in the North is highly uncertain, there is considerable likelihood that the newly formed Yukon and Northwest Territories power

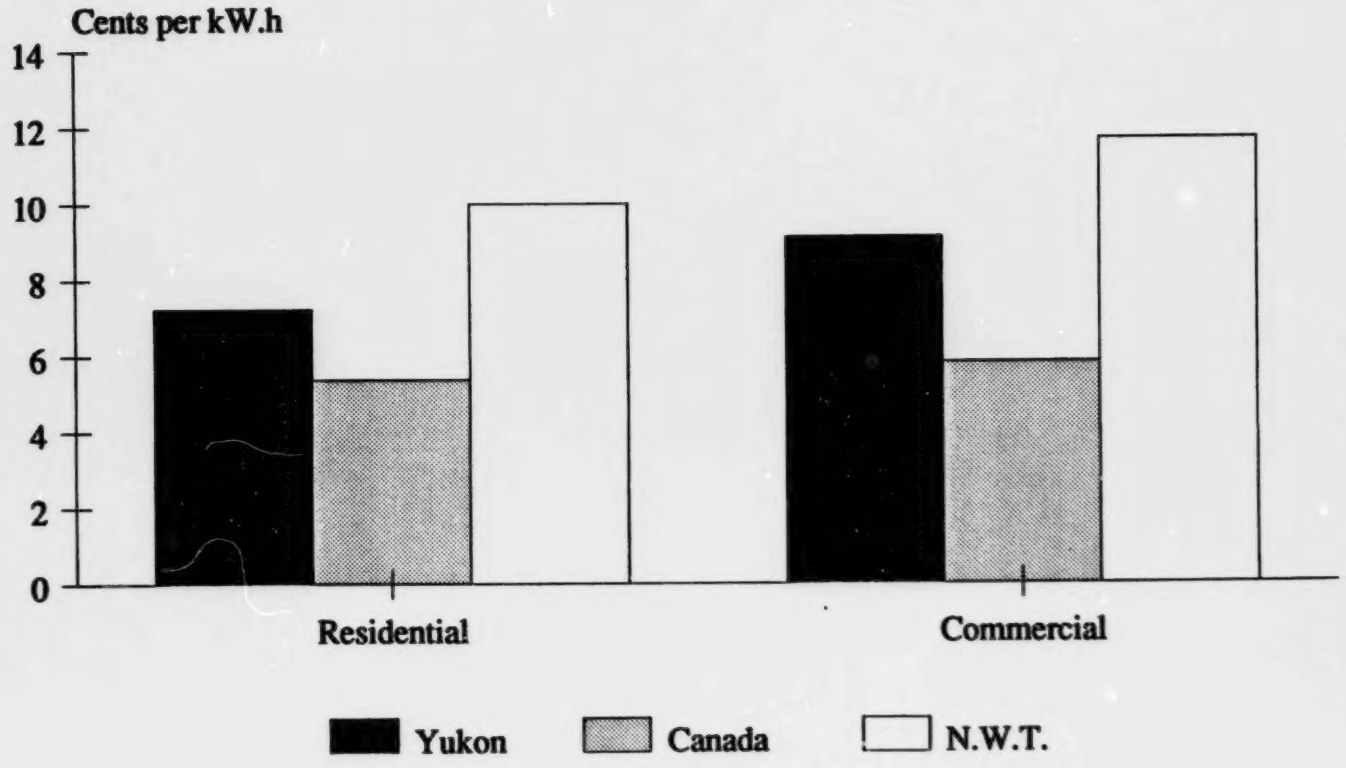
Figure B.4
Northwest Territory Electricity Demand
1987



Total Consumption: 467 GW.h

SOURCE: Statistics Canada, Electric Power Statistics, vol. 3, (Cat. 57-202).

Figure B.5
Electricity Prices in the Yukon
and Northwest Territories - 1987



SOURCE: EMR Canada, Energy Statistics Handbook.

Note: Assumes consumption of 1 000 kW.h for residential and 10 000 kW.h for commercial.

corporations, in an attempt to bring increased efficiency to the supply of electric power in their regions, will attempt to obtain significant modifications to the existing pricing system in order to reduce average electricity rates.

While electricity pricing will undoubtedly be an important issue over the next 10 years, the devolution of the NCPC to territorial ownership and control will undoubtedly add momentum to the search for alternatives to oil-fired electricity generation, while raising the profile of long-term planning and development in the North. This argument follows from the observation that the NCPC often appeared reluctant to show interest in relatively large-scale capital undertakings where uncertain or long-term payoffs were involved.[2] On the other hand, it has been suggested that the transfer of the NCPC's assets and responsibilities to the territories will spark renewed interest within the North in longer-term development projects, oriented towards lessening the region's dependence on oil-fired generation capacity.

The alternatives to diesel generation, which vary considerably between the two territories, consist largely of coal, natural gas and small hydro. In particular, surveys of the theoretical hydro development potential in the North identify as many as 180 sites, ranging in size from 5 MW to as much as 4850 MW. The development of hydro projects has historically been constrained by high initial capital expenditures. However, the rising cost of diesel generation has resulted in considerable interest being shown in the reassessment of the economic feasibility of a number of small hydro sites. In the context of the more distant future, Atomic Energy of Canada is in the process of refining a larger version of its Slowpoke nuclear reactor for use in remote locations in the North--primarily for heating purposes. If and when the utilization of nuclear power for this purpose occurs, it could result in a significant displacement of oil-fired electricity generation. In addition to a number of renewable energy test projects being conducted in the North, including one which generates electricity from wind, the more efficient use of existing diesel generation facilities is also being encouraged involving, for example, the use of waste heat recovery systems.

Although there are no known oil reserves in the Yukon, reserves do exist in the Northwest Territories. The viability of increased local use of these resources is an area which has been slated for greater investigation.

Footnotes

[1] A substantial amount of extra reserve capacity is maintained in the North to provide adequate security of supply to isolated communities throughout the long winter months.

[2] The NCPC has not chosen to develop hydro capacity prior to demand. This is largely due to its mandate, set out in the NCPC Act of 1956 and amended in 1975, which dictates that the Commission provide electrical service on a cost recovery basis.

APPENDIX C

FUTURE REQUIRED CAPACITY ADDITIONS

TABLE C.1

CANADA TOTAL
FUTURE REQUIRED CAPACITY ADDITIONS

		BASE SCENARIO				HIGH SCENARIO	
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH RESERVE	TOTAL SURPLUS	TOTAL SHORTFALL	TOTAL SURPLUS	TOTAL SHORTFALL
1988	100512	78382	90857	9677	-22	9677	-22
1989	103761	99679	92408	11381	-27	10368	-29
1990	104605	99679	94040	10598	-32	8684	-148
1991	106682	99679	96699	10053	-71	7238	-367
1992	110527	99679	99440	11465	-378	7602	-781
1993	110927	99679	102265	9492	-830	5301	-2134
1994	110927	99679	105176	7055	-1304	3460	-4513
1995	113957	99679	108177	7721	-1941	2096	-4511
1996	113957	99679	110577	5965	-2585	811	-7051
1997	113957	99679	113040	4647	-3730	287	-10490
1998	114057	99679	115569	3958	-5470	139	-14347
1999	114557	101937	118165	3711	-7319	56	-18019
2000	114557	104257	120834	2992	-9269	49	-22425
2001	114557	106271	123146	2096	-10685	46	-26511
2002	114557	108325	125505	1184	-12132	43	-30721
2003	115057	110421	127911	1110	-13964	40	-34560
2004	115057	112559	130365	766	-16074	37	-39031
2005	115057	114741	132870	414	-18227	33	-43639

SOURCE: Since the generating systems of the various provinces are not integrated, the cumulative surplus or shortage for Canada as a whole must be calculated separately.

TABLE C.2

BRITISH COLUMBIA TOTAL FUTURE REQUIRED CAPACITY ADDITIONS

		BASE SCENARIO			HIGH CASE	INCL. EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 15% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	12497	8054	9262	3235	3235	3235
1989	12497	8473	9744	2753	2648	2753
1990	12497	8914	10251	2246	2025	2246
1991	12497	9104	10469	2028	1689	2028
1992	12497	9298	10692	1805	1342	1805
1993	12497	9495	10920	1577	983	1577
1994	12497	9698	11152	1345	614	1345
1995	13017	9904	11390	1627	752	1627
1996	13017	10096	11611	1406	381	1156
1997	13017	10292	11836	1181	-2	681
1998	13117	10492	12066	1051	-297	451
1999	13617	10696	12301	1316	-203	216
2000	13617	10904	12540	1077	-621	-23
2001	13617	11118	12786	831	-1057	-269
2002	13617	11337	13038	579	-1505	-521
2003	14117	11560	13294	823	-1467	-777
2004	14117	11787	13555	562	-1944	-1038
2005	14117	12019	13822	295	-2435	-1305

1) Committed Capacity includes the return of Columbia River downstream benefits over a six year period beginning in 1998.

TABLE C.3

ALBERTA TOTAL
FUTURE REQUIRED CAPACITY ADDITIONS

		BASE SCENARIO			HIGH CASE	INCLUDING EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 22% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	7600	5823	7104	496	496	n.a.
1989	8006	6293	7677	329	246	n.a.
1990	8386	6801	8297	89	-90	n.a.
1991	8792	7135	8705	87	-195	n.a.
1992	8792	7486	9132	-340	-736	n.a.
1993	8792	7853	9581	-789	-1310	n.a.
1994	8792	8239	10052	-1260	-1919	n.a.
1995	8792	8644	10546	-1754	-2564	n.a.
1996	8792	9020	11004	-2212	-3184	n.a.
1997	8792	9412	11482	-2690	-3838	n.a.
1998	8792	9821	11981	-3189	-4527	n.a.
1999	8792	10248	12502	-3710	-5254	n.a.
2000	8792	10693	13045	-4253	-6021	n.a.
2001	8792	10830	13212	-4420	-6371	n.a.
2002	8792	10968	13381	-4589	-6729	n.a.
2003	8792	11108	13552	-4760	-7095	n.a.
2004	8792	11250	13725	-4933	-7470	n.a.
2005	8792	11394	13901	-5109	-7854	n.a.

TABLE C.4

SASKATCHEWAN TOTAL
FUTURE REQUIRED CAPACITY ADDITIONS

		BASE SCENARIO			HIGH CASE	INCL. EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 15% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	2845	2280	2622	223	223	n.a.
1989	2845	2397	2756	89	59	n.a.
1990	2945	2519	2897	48	-14	n.a.
1991	2945	2592	2980	-35	-132	n.a.
1992	3245	2666	3066	179	46	n.a.
1993	3245	2743	3155	90	-81	n.a.
1994	3245	2823	3246	-1	-214	n.a.
1995	3245	2904	3340	-95	-351	n.a.
1996	3245	2961	3405	-160	-461	n.a.
1997	3245	3019	3471	-226	-573	n.a.
1998	3245	3078	3539	-294	-689	n.a.
1999	3245	3138	3608	-363	-809	n.a.
2000	3245	3199	3679	-434	-932	n.a.
2001	3245	3246	3732	-487	-1038	n.a.
2002	3245	3293	3787	-542	-1147	n.a.
2003	3245	3341	3842	-597	-1259	n.a.
2004	3245	3390	3898	-653	-1374	n.a.
2005	3245	3439	3955	-710	-1491	n.a.

TABLE C.5

MANITOBA TOTAL
FUTURE REQUIRED CAPACITY ADDITIONS

YEAR	COMMITTED CAPACITY	BASE SCENARIO PEAK DEMAND	PEAK WITH 15% RES.	SURPLUS/ SHORTFALL	HIGH CASE SURPLUS/ SHORTFALL	INCL. EXPORTS SURPLUS/ SHORTFALL
1988	4125	3437	3953	172	172	172
1989	4125	3480	4002	123	80	123
1990	4381	3524	4053	328	241	328
1991	5021	3606	4147	874	740	874
1992	5405	3689	4243	1162	978	1162
1993	5405	3775	4341	1064	828	489
1994	5405	3862	4442	963	672	388
1995	5405	3952	4545	860	511	285
1996	5405	4022	4625	780	372	205
1997	5405	4093	4707	698	228	123
1998	5405	4165	4790	615	81	-190
1999	5405	4238	4874	531	-71	-274
2000	5405	4313	4960	445	-227	-360
2001	5405	4381	5039	366	-377	-439
2002	5405	4451	5119	286	-532	-519
2003	5405	4521	5200	205	-691	-600
2004	5405	4593	5282	123	-853	-682
2005	5405	4666	5366	39	-1021	-766

TABLE C.6

ONTARIO TOTAL
FUTURE REQUIRED CAPACITY ADDITIONS

	BASE SCENARIO				HIGH CASE	INCLUDING EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 22% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	32955	23816	29294	3661	3661	n.a.
1989	34717	23978	29493	5224	4907	n.a.
1990	34717	24142	29695	5022	4382	n.a.
1991	35598	24684	30361	5237	4254	n.a.
1992	36479	25238	31043	5436	4091	n.a.
1993	36479	25805	31740	4739	3013	n.a.
1994	36479	26384	32452	4027	1900	n.a.
1995	36479	26976	33180	3299	749	n.a.
1996	36479	27280	33554	2925	-39	n.a.
1997	36479	27587	33932	2547	-844	n.a.
1998	36479	27897	34314	2165	-1666	n.a.
1999	36479	28211	34700	1779	-2507	n.a.
2000	36479	28529	35091	1388	-3368	n.a.
2001	36479	28993	35662	817	-4447	n.a.
2002	36479	29465	36242	237	-5558	n.a.
2003	36479	29945	36832	-353	-6699	n.a.
2004	36479	30432	37431	-952	-7870	n.a.
2005	36479	30927	38040	-1516	-9074	n.a.

TABLE C.7

QUEBEC TOTAL
FUTURE REQUIRED CAPACITY ADDITIONS

		BASE SCENARIO			HIGH CASE	INCL. EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 10% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	32458	28688	31557	901	901	901
1989	33514	28531	31384	2130	1794	2130
1990	33514	28374	31211	2303	1630	2303
1991	33514	29259	32185	1329	287	1329
1992	35414	30172	33189	2225	787	2225
1993	35414	31113	34224	1190	-671	1190
1994	35414	32083	35292	122	-2191	122
1995	37924	33084	36392	1532	-1265	432
1996	37924	33983	37382	542	-2760	-1108
1997	37924	34907	38398	-474	-4311	-2674
1998	37924	35856	39442	-1518	-5922	-4268
1999	37924	36831	40514	-2590	-7593	-5890
2000	37924	37832	41615	-3691	-9329	-7541
2001	37924	38736	42609	-4685	-10975	-8535
2002	37924	39661	43627	-5703	-12678	-9553
2003	37924	40608	44669	-6745	-14441	-10595
2004	37924	41578	45736	-7812	-16265	-11662
2005	37924	42571	46828	-8904	-18153	-12754

1) Quebec capacity includes 5200 MW firm capacity from Churchill Falls.

TABLE C.8

NEW BRUNSWICK TOTAL FUTURE REQUIRED CAPACITY ADDITIONS

		BASE SCENARIO			HIGH CASE	INCL. EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 20% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	3471	2525	3030	441	441	441
1989	3471	2606	3127	344	311	344
1990	3471	2689	3227	244	175	244
1991	3471	2776	3331	140	32	140
1992	3701	2866	3439	262	113	32
1993	4101	2959	3551	550	357	320
1994	4101	3055	3666	435	195	-35
1995	4101	3154	3785	316	25	-394
1996	4101	3228	3874	227	-115	-483
1997	4101	3305	3965	136	-261	-574
1998	4101	3383	4059	42	-411	-668
1999	4101	3462	4155	-54	-567	-764
2000	4101	3544	4253	-152	-728	-862
2001	4101	3617	4340	-239	-880	-949
2002	4101	3691	4429	-328	-1036	-1038
2003	4101	3767	4520	-419	-1198	-1129
2004	4101	3844	4613	-512	-1365	-1222
2005	4101	3923	4708	-607	-1536	-1317

1) 230 MW of Point Lepreau capacity is excluded until 1992

TABLE C.9

NOVA SCOTIA TOTAL
FUTURE REQUIRED CAPACITY ADDITIONS

		BASE SCENARIO			HIGH CASE	INCL. EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 20% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	2345	1706	2047	298	298	298
1989	2345	1809	2171	174	150	174
1990	2345	1919	2303	42	-7	42
1991	2495	1980	2376	119	42	119
1992	2645	2043	2451	194	88	194
1993	2645	2107	2529	116	-21	116
1994	2645	2174	2609	36	-135	36
1995	2645	2243	2692	-47	-253	-47
1996	2645	2301	2761	-116	-360	-118
1997	2645	2361	2833	-188	-471	-488
1998	2645	2422	2906	-261	-586	-861
1999	2645	2485	2982	-337	-705	-1237
2000	2645	2549	3059	-414	-828	-1614
2001	2645	2606	3128	-483	-944	-1683
2002	2645	2665	3198	-553	-1064	-1753
2003	2645	2725	3270	-625	-1188	-1825
2004	2645	2786	3344	-699	-1317	-1899
2005	2645	2849	3419	-774	-1449	-1974

TABLE C.10

PRINCE EDWARD ISLAND TOTAL FUTURE REQUIRED CAPACITY ADDITIONS

			BASE SCENARIO		HIGH CASE	INCL. EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 15% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	124	127	146	-22	-22	n.a.
1989	124	131	151	-27	-29	n.a.
1990	124	136	156	-32	-36	n.a.
1991	124	138	159	-35	-40	n.a.
1992	124	141	162	-38	-45	n.a.
1993	124	143	165	-41	-49	n.a.
1994	124	146	167	-43	-54	n.a.
1995	124	148	170	-46	-59	n.a.
1996	124	150	172	-48	-63	n.a.
1997	124	152	174	-50	-68	n.a.
1998	124	153	176	-52	-72	n.a.
1999	124	155	178	-54	-76	n.a.
2000	124	157	181	-57	-81	n.a.
2001	124	159	183	-59	-86	n.a.
2002	124	161	185	-61	-91	n.a.
2003	124	163	187	-63	-96	n.a.
2004	124	165	190	-66	-101	n.a.
2005	124	167	192	-68	-106	n.a.

1) Most PEI electricity demand is already satisfied by firm power imports from New Brunswick and Quebec.

TABLE C.11

NEWFOUNDLAND TOTAL FUTURE REQUIRED CAPACITY ADDITIONS

			BASE SCENARIO		HIGH CASE	INCL. EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 17% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	1772	1384	1619	153	153	153
1989	1797	1424	1666	131	113	131
1990	1905	1465	1715	190	154	190
1991	1905	1496	1751	154	98	154
1992	1905	1528	1787	118	40	118
1993	1905	1560	1825	80	-20	80
1994	1905	1592	1863	42	-82	42
1995	1905	1626	1902	3	-145	3
1996	1905	1670	1954	-49	-223	-49
1997	1905	1715	2006	-101	-304	-101
1998	1905	1761	2061	-156	-388	-156
1999	1905	1809	2116	-211	-475	-211
2000	1905	1858	2173	-268	-565	-2268
2001	1905	1895	2217	-312	-642	-2312
2002	1905	1933	2261	-356	-721	-2356
2003	1905	1971	2306	-401	-802	-2401
2004	1905	2011	2353	-448	-886	-2448
2005	1905	2051	2400	-495	-973	-2495

1) Excludes Labrador. Peak demand calculated by adding the generating capacity of Newfoundland Light & Pow to the expected peak demand of Newfoundland & Labrador Hydro, since the latter's peak demand includes sales to the former.

TABLE C.12

YUKON AND NORTHWEST TERRITORIES TOTAL FUTURE REQUIRED CAPACITY ADDITIONS

		BASE SCENARIO			HIGH CASE	INCL. EXPORTS
YEAR	COMMITTED CAPACITY	PEAK DEMAND	PEAK WITH 20% RES.	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL	SURPLUS/ SHORTFALL
1988	320	186	223	97	97	n.a.
1989	320	196	235	85	59	n.a.
1990	320	196	235	85	59	n.a.
1991	320	196	235	85	59	n.a.
1992	320	196	235	85	59	n.a.
1993	320	196	235	85	59	n.a.
1994	320	196	235	85	59	n.a.
1995	320	196	235	85	59	n.a.
1996	320	196	235	85	59	n.a.
1997	320	196	235	85	59	n.a.
1998	320	196	235	85	59	n.a.
1999	320	196	235	85	56	n.a.
2000	320	199	239	81	49	n.a.
2001	320	199	239	81	46	n.a.
2002	320	199	239	81	43	n.a.
2003	320	199	239	81	40	n.a.
2004	320	199	239	81	37	n.a.
2005	320	200	240	80	33	n.a.

APPENDIX D

UNITED STATES EXPERIENCE

Appendix D

UNITED STATES EXPERIENCE

D.1 Structure of the Industry

The electricity utility industry in the United States is characterized by a diverse range of firms, organizational structures and institutions. In 1987, total U.S. installed generating capacity was 718 GW of which investor-owned utilities accounted for 76 percent. Municipal and federal government sources accounted for 19 percent and the remaining 4 percent was owned on a cooperative basis.[1] A small but growing amount of electricity is also supplied by non-utility sources such as cogenerators and independent power producers while statistics are uncertain, they appear to account for about 25 GW or 3.5 percent of total U.S. generating capacity.

Investor-owned utilities tend to be large, vertically integrated firms with their own generating plant, transmission systems and franchised service areas. While much of their output is sold to retail customers, bulk power sales to other utilities are an important and rapidly growing market. Most of these investor-owned utilities are independent firms but approximately one-quarter are organized under holding company structures.[2]

On the basis of numbers alone, the largest portion of the publicly-owned utility sector is comprised of municipally owned firms. These firms purchase a significant part of their electricity requirements from other utilities--both public and private--and distribute the power on a retail basis in a franchised service area. The remaining publicly-owned utilities are federal hydroelectric facilities operated by the Army Corps of Engineers or the Bureau of Reclamation. The existence of these facilities stems from federal constitutional control of major waterways. The output from these plants is sold through Power Marketing Administrations which have a legal mandate to give preferential access to other federal customers, cooperatives and publicly-owned utilities. Similar discriminatory access is provided by the Tennessee Valley Authority, a federal agency which owns and operates coal and nuclear facilities and has what amounts to a franchised service area.

Cooperative utilities--those owned by their customers--can be organized for distribution only, where the power is purchased from other utilities on a wholesale basis, or they may also own some generation and transmission capacity.

While the electric industry is characterized by many firms, these firms do not operate in total isolation from one another. In order to facilitate the transfer of large volumes of bulk power, networks of extra-high voltage transmission lines and connections have evolved. There are three such networks in existence today: the Texas Interconnected System, confined geographically to that state; the Western Interconnected System, covering the region southwest and west of the Rocky Mountains; and the Eastern Interconnected System, covering the eastern two-thirds of the country. These networks remain largely unconnected with one another either by choice or due to technical and cost considerations.

These networks allow the movement of bulk power on a regional basis. However, utility integration extends beyond the sharing of bulk power. All utilities within a network are intertied to their adjacent utilities. These connections facilitate cooperation between and among utilities which can range from informal bilateral arrangements to highly structured power pools involving coordinated planning and operation. It is estimated that there are approximately thirty power pools in existence today, nine of which are formal integrations where the members operate essentially as a single utility.[3]

In addition to these arrangements, every utility is a member of one of the nine regional councils which make up the North American Reliability Council. These councils are charged with promoting reliability and adequate bulk power supplies on a regional level. The expansion plans of the member utilities are evaluated in order to determine regional impacts and the reliability of future (and existing) electric systems.

D.2 Regulatory History

Electric utilities in the United States have been regulated in one form or another over most of their 100-year history. The primary rationale behind instituting regulation as we know it today was the "natural monopoly" argument. In its development years, the industry was characterized by large economies of scale where production costs fell as output rose. These economies were often of sufficient magnitude relative to the size of the market that the lowest cost of production would be achieved if only one supplier operated in the market. Even in the absence of state-backed monopoly status, a single supplier could emerge through competition as a larger producer and could price his rivals out of the market. Hence, in the absence of government interference, natural economic forces would result in the evolution of monopoly firms.

Political authorities perceived that consumers could be supplied at a lower cost by one monopoly producer enjoying large economies of scale than by several smaller producers with higher costs. Furthermore, as each customer must be physically linked to the supplier's distribution network, multiple suppliers would not provide the consumer with reasonable substitution or switching opportunities and would result in a costly and inefficient duplication of systems. For these reasons, many state and local authorities granted the utilities in their jurisdiction de facto monopoly status by licensing franchised service areas.

The granting of monopoly status, however, conferred significant market power on the firms which they could use to increase price and reduce output. This could lead to sustainable supernormal profit at the expense of electric consumers. Further, the utility would be free to practise unfair price discrimination among its customers; that is, charge different consumers different prices which are not based solely on the differences in costs of servicing. Concern over such issues led to the regulation of prices and profit. This regulatory function is generally carried out by commissions or agencies instituted on a state level, although the constitutional division of powers also passes this responsibility to the federal level in some instances. As the industry has grown and social and political concerns have changed, the regulation of electric utilities has expanded to include construction programs, facility siting, financial structures and environmental impacts. Virtually every facet of the industry is now regulated by a myriad of local, state and federal agencies.

The regulatory procedure generally follows an adversarial hearing format. If a utility wishes to undertake a large project or requires a price increase, it makes an application to its particular regulatory agency. If warranted, the agency convenes a hearing where all interested parties are allowed to participate and cross-examine witnesses. The agency examines the information presented at the hearing and makes its decision accordingly.

These procedures worked well during the 1950s and 1960s and provided benefits for both producers and consumers. The industry was experiencing rapid technological progress and large economies of scale. Costs fell as the quantity produced rose and the optimal size of generating plants increased. It was a time of rising demand in response to growth in incomes and economic activity. Demand growth was actively promoted in an effort to take advantage of the economies of scale and technological progress available. This resulted in productivity increases which offset any increase in cost due to the comparatively low inflation rates which existed over the period. The real price of electricity fell and applications to commissions were infrequent.

This period of relative calm and stability did not last into the 1970s. The rate of inflation began to rise, increasing operating costs faster than in the past. Protection of the environment became a major issue and resulted in the passage of the Clean Air Act in 1970 which stipulated stringent reductions in the level of sulphur emissions and other pollutants. Electric utilities were faced with the option of installing expensive pollution control equipment or switching to alternate fuels. The use of low-sulphur coal increased operating costs as it was more expensive than the high-sulphur varieties. The price of coal began to rise in general, reflecting the higher production costs caused by the implementation of stricter mine safety standards.

In order to comply with the new environmental standards, many utilities invested large sums of money to convert existing coal-fired units to oil. Fuel costs to oil-burning utilities rose dramatically when, among other things, the policies of OPEC in 1973-1974 resulted in unprecedented increases in the price of delivered oil. All utilities were affected since escalating oil prices caused increases in the price of other energy sources including coal and gas. The U.S. government strongly encouraged utilities to convert (or reconvert) from oil to domestic coal so as to reduce the country's dependence on foreign energy sources. Inflation rates reached an all-time high and interest rates kept apace, further driving up the cost of new construction and conversions. Concurrent with rising costs, the benefits from economies of scale and technological progress appeared to have been exhausted and productivity increases slowed.

Some utilities tried to protect themselves from rising fossil-fuel prices by building nuclear generating capacity. However, construction costs greatly exceeded expectations as inflation, interest rates and labour costs rose. After the 1979 incident at Three Mile Island, regulatory safety standards were tightened substantially. Both capital and operating costs rose as new equipment and safety procedures had to be installed and designs had to be modified. Construction lead times increased as environmental and citizens groups intervened in siting and licensing procedures.

The impact of these events on the U.S. electric utility industry was dramatic. Costs rose rapidly but utilities were not able to increase prices quickly enough within the existing regulatory framework and their earnings fell. As many were trying to finance construction programs, reduced earnings implied increased demands on external financing. Financial markets reacted adversely and many utilities had their bond rating downgraded. This meant not only higher interest charges to float debt but also a reduction in the amount of debt capital available since, by law, many institutional investors cannot purchase debt that carries a low rating. The issuance of stock was also not a particularly attractive option. Investors perceived that the industry's low earnings would not be sufficient to provide the desired return and the market bid the price down, often to below book value. This created a capital loss for existing investors and diluted the value of existing stock. Further, a larger volume of stock would have to be sold to raise a given sum or a higher return would be required to prevent market prices from being further discounted in the market.

Utilities attempted to mitigate the decline in earnings by filing for rate increases. By the time rate increases were allowed, rapidly rising costs meant that the prices were out of date and firms were often forced to file for another increase immediately. The number of rate cases mushroomed, severely taxing the limited resources of state commissions which were unprepared for this unprecedented workload. This increased the length of time required to conduct the rate review, driving a larger wedge between prices and underlying costs. Moreover, the price increases requested were not trivial and consumer opposition coalesced. This not only further lengthened the procedural time but it also politicized the regulatory process. As the regulatory arena became more politicized, regulatory authorities became increasingly reluctant to grant the full increases requested. The entire problem was magnified when expensive new plants were finished. The addition of such plants to a utility's rate base imply large price increases which have come to be known as "rate shocks."

This general situation was exacerbated by falling demand for electricity. The oil price shocks of the 1970s and the world recession of the early 1980s fundamentally altered the economic structure of the country. Economic growth declined and, with it, the growth of electricity demand. Rising electricity prices also boosted conservation. After decades where the demand for electricity grew at an average of 7 percent per year, the average rate declined to 3 percent or less. The lead time required to build a new generating unit, however, is approximately 10 years and many of the plants under construction or recently completed were begun before the decline in demand became evident or was perceived as being permanent. Consequently, many utilities were left with unrequired capacity that often cost much more than had been originally anticipated.

Rising consumer militancy meant it was much more difficult for the utilities to obtain rate increases sufficient to cover their higher costs. While the experience differed from jurisdiction to jurisdiction, many regulatory commissions granted what are perceived to be less-than-adequate price increases. Some instituted ex post prudence reviews that disallowed large portions of the costs the utilities had attempted to recover, on capacity that the commission had already approved.

Insufficient price increases and disallowances shift the risks from the rate payer to the utility shareholder as it is the latter which must ultimately absorb unrecovered expenditures. This "rate suppression" has made many U.S. investor-owned utilities reluctant to finance new projects for fear of being unable to recover the total cost incurred. Many have cancelled plans for new capacity and have halted construction on plants in progress. However, demand has continued to grow, albeit at a slower rate, and excess capacity in some jurisdictions is declining. Given the lead time for new plants, there is significant concern that insufficient capacity will become a problem in some regions of the U.S. in the near future. While other areas have a surplus of capacity which could be used to provide power to deficit areas, there is often insufficient transmission capacity available. Moreover, the siting of new high voltage transmission lines is becoming increasingly difficult with the intervention of environmental groups and increasing concern over the public health and safety implications of high-voltage transmission lines. **Indeed, many argue that it is transmission system capacity that is likely to be the largest obstacle to sufficient, reliable electricity supply in the future.**

D.3 Legislation and Regulatory Jurisdiction

There are many legislative acts governing the electric utility industry which authorize and delineate the responsibilities of various federal and, by implication, state authorities. The most important of these are discussed below.

D.3.1 The Public Utilities Holding Company Act (1935).

During the 1920s and early 1930s, the electric utility industry evolved into a holding company structure; 16 companies owned 75 percent of the power produced in 1932.[4] Fear of discriminatory cross-subsidization and pricing at the expense of the consumer led to the passage of the Public Utility Holding Company Act (PUHCA) in 1935. The Act was designed to break up ownership concentration unless there were clear offsetting efficiency gains present in the current structure. A holding company is defined as a firm which controls, directly or indirectly, 10 percent of the voting stock of a public utility or a firm which the Securities and Exchange Commission (SEC) deems to wield sufficient power to require regulation.

Such companies must register with the SEC and are subject to its regulation on matters concerning corporate structure, dissemination of financial information and the purchase by the utility of non-utility related services. The company is also subject to oversight on internal operating practices, proxy solicitations and contracts for sales, service and construction. The Act requires that holding companies be limited to those which operate in a single interconnected and coordinated system within a single region or area. Companies which are only financially rather than physically integrated are generally not allowed. Holding companies that operate solely within a single state's boundaries or within its own state and adjacent ones or those which generate most of their revenue from non-utility sources are exempt. As of March 31, 1986, there were nine regulated holding companies with a total of 50 subsidiaries.

D.3.2 Federal Power Act (1935)

In 1935, Congress enacted the Federal Power Act (amended in 1976) to give the Federal Power Commission (FPC) increased regulatory authority over the interstate commerce activities of electric utilities. The Commission was already responsible for the licensing of hydroelectric facilities on major federal waterways. The Act added mergers, consolidations, property sales, security issues and adequacy of service to the Commission's oversight responsibilities. It also authorized the creation of a standard set of accounting procedures.

The legislation gave the FPC control over power pooling and a mandate to promote cooperation among utilities. Its authority over power pooling was limited to a review, and possible modification, of rate schedules for transmission services which are voluntarily filed by member utilities. The Act also gave the Commission regulatory power over wholesale power sold on an interstate basis. The Commission could set rates and could, upon complaint, order a private utility selling interstate power to connect and sell to another utility. Its powers stopped short of being able to order mandatory wheeling.

D.3.3 Environmental Regulations

Between 1969 and 1981, over forty environmental statutes were enacted by the U.S. Congress[5] and a myriad of legislation was passed at the state level. The impact of many of the federal bills--such as the Endangered Species Act--on the electric utility industry tend to be site and project specific. There are two Acts, however, outside of the nuclear area which have particularly important implications for the industry. These are the Clean Water Act and the Clean Air Act.

The Clean Water Act of 1972 and its 1977 Amendments laid the foundation for national control of water pollution by prohibiting the discharge of pollutants into a public waterway without a permit. The Environmental Protection Agency (EPA) was provided with a mandate to create and enforce pollution control standards based on technology. Enforcement of the standards was to occur in two phases. The first stipulated that, by 1977, each discharger was to install the "best practicable control technology." The second phase established specific criteria for each pollutant and mandated that each discharger install the best available (economic) technology to meet these criteria. The Act also required all dischargers to comply with existing state statutes by 1977. State legislation often involved standards that were stricter and more comprehensive that those established by the EPA.

The Clean Water Act is particularly important to electric utilities because of the discharge of heated water (used for cooling purposes) and chemical pollutants from power plants. The EPA issued specific standards for both new and existing steam generation plants which limited the discharge of effluent. It also attempted to impose a zero-discharge standard which was to be met by 1981, but this was overturned by the courts.

Growing environmental concern also prompted Congress to introduce the Clean Air Act, which was passed in 1963 and first amended in 1965. However, it is largely the Amendments of 1970, 1974 and 1977 which determined the statutory framework in existence today. The Act authorized the EPA to develop regulations to set and achieve national ambient air-quality standards. The Agency developed standards for each pollutant which were based on public health and welfare effects. Congress also stipulated in the Act that individual states had to institute specific implementation plans to ensure compliance with national standards. The initial deadline was 1977 but it was later extended to 1982.

This extension was part of the 1977 Amendments which also imposed the requirement for preconstruction reviews, monitoring and permits for all new or "modified" plants which emit pollutants. In order to obtain a permit within an area where existing air-quality standards are below the national standards, the owner of the plant must show, among other things, that the plant contains the "lowest achievable emission rate technology" and that total emissions in the area will decline. This latter condition implies that the owner of the plant must purchase pollution control equipment for other plants in the area, either his own or those owned by others, in order for total emissions to decline once the new plant begins operation.

Initially, the EPA did not impose pollution regulations and standards in areas where the existing air-quality exceeded the national standards. However, in response to a court challenge, the Agency was required to set regulations in order to prevent a "significant deterioration" in the ambient standards in such areas. Many of the EPA's regulations arising from this order were adopted by Congress in its 1977 Amendments.

These Amendments divided the clean-air areas into three classes according to the existing air quality. Each class was assigned a maximum allowable increase in pollutants, with the lowest increase being applied to the most pristine areas and growing progressively larger for the more polluted categories. The Amendments also served to increase the total number of plants subject to preconstruction review and regulatory oversight. The monitoring requirements for the review were enlarged and the entire review process was opened up to public scrutiny. Finally, major emitting facilities were required to install and use the "best available control technology."

Another important aspect of the Clean Air Act as it relates to electric utilities is that it authorized the EPA to set performance standards to limit emissions from large stationary sources of air pollutants, including fossil-fuelled steam generators. The initial set of regulations, which became effective at the end of 1971, set limits on emissions which could often be met more cheaply by switching to an alternate fuel, rather than continuing to burn less expensive high-sulphur coal and purchasing the required flue-gas desulphurization equipment. In 1977, however, significant changes were made to these provisions. The resulting EPA regulations were stricter and required that new source plants must not only meet maximum allowable standards but must also show a significant reduction from the allowable level of potential uncontrolled sulphur dioxide emissions. Further, the use of continual control mechanisms was mandated. The effect of these two provisions has been that all new plants now require flue-gas desulphurization systems.

D.3.4 National Energy Act (1978)

In 1978, Congress passed a series of Acts under the umbrella of the National Energy Act, designed to create a comprehensive energy policy for the nation. The desire and focus for the policy arose out of a concern for security of energy supply, following the price shocks of the early 1970s and a growing national dependency on foreign energy supplies. The purpose of the various Acts was to promote energy conservation, keep utility bills low and to allocate scarce fuel supplies to the most efficient uses. The first goal was embodied in the Energy Conservation and Policy Act. The Power Plant and Industrial Fuel Use Act[6] prohibited the use of oil and gas to generate electricity in new power plants. Existing power plants were also expected to convert to coal, although a complex series of cost-based exemptions were allowed. This encouragement of coal was in direct conflict with the focus of existing environmental regulations discussed earlier.

The efficient use of resources was encouraged by the passage of two further Acts: The Public Utilities Regulatory Act and the Public Utilities Regulatory Policies Act (PURPA). The former piece of legislation required utilities to file marginal cost data to the Federal Energy Regulatory Commission (FERC), the successor to the FPC, on a regular basis. It also stipulated that state regulatory commissions must hold public hearings on the pricing of electric services on the basis of seasonal and daily variations in demand. Of all of the Acts passed, the provisions of PURPA have proven to be the most important for electric utilities in the U.S. They have had, and will continue to have, a significant impact on the performance and structure of the industry. As such, an entire section is devoted to PURPA and its impacts later in this report.

D.3.5 State Jurisdiction and Regulatory Responsibilities

The above discussion relates to federal legislation and responsibilities but the states are also actively involved in the regulation of electric utilities. In general, federal jurisdiction covers wholesale transactions, interstate activities and activities among utilities, while state jurisdiction relates primarily to transmission siting and retail activities. The states regulate private utilities, publicly-owned utilities and some cooperatives. There are hundreds of pieces of state legislation and while there is considerable variation among states, most allow for the regulation of retail rates, quality of service, franchised service areas, entry and exit, siting, construction and safety.

D.4 The Public Utility Regulatory Policies Act and Its Implications

PURPA was, for all intents and purposes, an unprecedented federal excursion into rate design and utility purchase obligations--areas traditionally considered to be state jurisdiction. It amended the Federal Power Act and expanded FERC's jurisdiction in some instances and clarified its responsibilities in others. The stated goals of the Act were to encourage the conservation of electricity, to promote the efficient use of utility resources, and to provide fair and equitable rates for electric consumers. Congress believed that these goals would be furthered by the development of cogeneration and small power production. Consequently, the Act included provisions to eliminate the institutional barriers to their development and to create a protected market for such facilities, as suppliers of wholesale power. The Act directed the FERC to establish rules in order to implement the Act's requirements. These, however, did not come into full effect until 1983 when the Supreme Court upheld the validity of both the Act and the subsequent FERC rules.

In the Act, a cogenerator is defined as a facility which produces electricity as a by-product from another production process and which meets several other criteria relating to system configuration, heat utilization and minimum efficiency standards. A qualifying facility (QF) is defined as a small power facility with a total capacity of less than 80 MW at one site and which uses biomass, waste, geothermal or renewable energy to meet at least 75 percent of its fuel requirements. Utility participation in such facilities is limited to a maximum of 49 percent ownership.

If they can show that they meet the above criteria, cogenerators and qualifying facilities are entitled to take advantage of PURPA's special provisions. The Act provides automatic exemption from regulation as public utilities under the Federal Power Act, the Public Utilities Holding Company Act and the Power Plant and Industrial Fuel Use Act. These facilities are also exempted from state regulation relating to financial matters and the fixing of rates. These special exemption provisions create a considerably simplified environment to encourage development, as the facilities are relieved of a myriad of regulations ranging from rate-of-return regulation through to the required use of detailed accounting methods.

Beyond the above exemptions, PURPA required electric utilities to purchase all output from QFs and cogenerators at rates that were just and reasonable, non-discriminatory and in the public interest. Further, these rates were *not to exceed the cost to the electric utility of the electric energy which, but for the purchase from such cogenerators or small power producers, such a utility would generate or purchase from another source*. This has come to be known as the "avoided cost" standard. The rates at which the utility provides standby or backup power must also be just and reasonable and nondiscriminatory. Facilities without QF status may also sell to electric utilities but purchase is not mandatory. These facilities must negotiate their rates with the utilities and do not qualify for the special exemptions.

The FERC set up guidelines concerning the determination of avoided cost and the factors which should be weighed in this calculation. However, the actual calculation of "avoided cost" rates was left up to the individual states. The FERC also refused to endorse a particular methodology, preferring instead to allow state commissions to choose the method most suited to their particular situation. As a result of the wide latitude given to the individual states, the methodologies used to set avoided cost rates and the rates themselves vary considerably among the states.

Building upon the FPC foundations, PURPA clarified and expanded the FERC authority with respect to interconnection and power pooling. The Act did not grant the FERC authority to organize power pools but did expand its responsibilities to encourage and promote such pools. It also provided the Commission with limited power to exempt utilities from individual state regulations or laws which prevented voluntary coordination among utilities. The FERC can also order interconnection among or between utilities in instances where it would promote energy and capital conservation or would improve the reliability and efficiency of the affected electric network.

Part and parcel of the regulation of bulk power markets is the question of wheeling. Wheeling is the transfer of electricity between two parties over a transmission network owned by a third party. Voluntary transactions of this sort are filed with the FERC and are subject to its oversight. PURPA specified that the Commission could order mandatory wheeling on an unwilling utility only if it found through a public hearing process that the order would:

1. be in the public interest;
2. result in energy conservation or improved reliability or efficient use of resources and facilities; and
3. not result in any undue burden on affected parties.

The latter condition means that no affected party should bear additional costs because of the order for which it is not compensated and that the order should not impair the ability of the wheeling utility to render adequate service to its customers. Further, wheeling cannot be ordered if it would serve to provide transmission services to an ultimate end user (i.e., limited to wholesale) or significantly alter existing competitive relationships. This last provision implies that a wheeling order cannot be issued if it would cause a utility to lose wholesale customers within its service area. Given the above stipulations, the FERC does not believe it has the legislative authority to implement mandatory wheeling.

As noted previously, the implementation of the PURPA provisions, particularly those pertaining to avoided cost and QFs, was left up to the individual states, albeit with FERC guidance. Avoided cost is essentially what the utility would have paid for its required energy and/or capacity if it had purchased it from another source other than the QF. Problems arise in attempting to determine what the other sources might have been and what price would have been paid. The utility itself is an alternative as it could build a plant to supply its requirements. This leads to the question of what type of plant would have been constructed and at what cost. Each aspect has to be valued now and in the future, giving rise to the usual problems associated with forecasting. Finally, there is no "true" methodology to determine avoided costs so the resulting state practices and rates vary enormously.[7]

A study carried out for the U.S. Department of Energy[8] found evidence that the implementation of PURPA has achieved some of the goals set forth in the Act. There has been an increase in the number of qualifying facilities, which implies an expanded range of technologies used in electric generation, and a reduced need for new capital investment by some utilities. Some of the states have implemented PURPA in a manner consistent with economic efficiency. However, the study also found evidence that in some jurisdictions, the encouragement of QFs has resulted in higher costs to consumers and an increased use of oil and gas. Both effects are opposite to the stated intentions of PURPA. Some of the inefficiencies found include:[9]

1. the setting of rates greater than full avoided cost;
2. requiring utilities to pay for capacity when it does not require the capacity;
3. a blurring of the lines between sunk costs and avoided costs;
4. the setting of rates without consideration of QF reliability and availability;
5. the adoption of incentive payments to encourage development that are not based on avoided cost;
6. the use of state-wide uniform rates which do not take into account the variation in avoided cost among utilities;
7. the mandated purchase of QF output in instances where it forces the utility to deviate from its most efficient dispatching and operating practices; and
8. restricting utilities from competitively soliciting least-cost sources of capacity if such is not provided by the QFs.

All of these factors serve to create rates to QFs and cogenerators which deviate from the individual utility's full avoided cost consistent with its least-cost expansion opportunities. As a consequence, prices which do not reflect the true cost to society result in an inefficient use of resources. Furthermore, PURPA placed certain restrictions on size, fuel, efficiency and operating standards, and utility ownership. These arbitrary restrictions have caused investment decisions to be biased towards those that will qualify for QF status and away from those which may occur in an unrestricted market where decisions are based solely on cost and efficiency factors.

As noted above, the variety of avoided cost methodologies used by the individual states has resulted in a great diversity in QF rates. This has had two important impacts. The first is the regional diversity with respect to the development of QFs and cogenerators. The ultimate potential for these facilities depends on resource and fuel endowments (e.g., wind and waste), industrial base and concentration, and industrial growth. The economics of individual projects vary with energy prices, technology and other factors such as plant design and age. Hence, regional response to a uniform price will vary and the variations may increase with divergent prices for PURPA power. Some states, notably Texas and California, have had significant QF and cogeneration response, while others have had little. The evidence suggests that California's experience is largely due to the setting of long-term QF rates that now exceed avoided cost, while the Texas case relates partly to a favourable industrial base.

The second important impact of diversified QF rates has been the creation of a desire to "shop around" by both buyers and sellers. For example, a QF operating within one utility's service area may be able to receive a higher avoided cost rate from an adjacent utility. Payments to QFs ultimately impact consumer rates so that, in a similar vein, a buyer in one jurisdiction may be able to purchase at a more favourable rate from another utility in another jurisdiction. The spatial variation in rates has created pressure from QFs and large customers for the right to "shop around" for the best price. This, of course, has implications for transmission access and mandatory wheeling as well as the entire structure of the industry, since this pressure arises both in the wholesale and retail markets.

D.5 Changing Directions in Regulation

Over the last 10 years, the implementation of PURPA has had a significant impact on the electric industry in the U.S. The encouragement of QFs and cogenerators has greatly increased the importance of non-utility sources of power. In some cases, this is viewed as a desirable outcome as it can reduce the capital investment required by utilities to meet future demand. Utilities which are unwilling to make new investments because of a perceived breakdown in regulatory procedures welcome such alternate sources. In other cases, the non-utility sector provides additional capacity, some of which may not be required but which the utility is mandated to purchase. In these instances, the cost of meeting electricity demand may rise and excess capacity becomes an issue. Reducing prices in order to increase the capacity used or to maintain customer load leads to a variety of problems and pressures such as the "shop around" concept discussed above. Transmission access is an integral part of this question and mandatory wheeling has become a very hotly debated item among all industry participants in the United States.

Much of the current discussion in the industry centres around concerns about economic efficiency and the least-cost source of power. While there is general agreement that the primary goal in the industry should be to provide adequate electric services at the lowest possible cost using the most economic combination of resources, there is widespread disagreement on how this can be achieved. This debate has been fuelled by the general trend towards deregulation in the American economy. Proponents of deregulation argue that an efficient outcome is unlikely when a market is controlled by bureaucratic and administrative procedures. They believe that unleashing competitive forces will provide for an efficient use of resources and lower costs in the long run. Others maintain that the electric industry is not workably competitive in all areas so, in order to prevent the abuse of market power, regulation must replace natural economic forces. Proponents of this view believe that the current regulatory framework can be adjusted in order to solve some of the current problems and to provide more efficient outcomes. A myriad of other solutions covering the entire spectrum between deregulation and regulation have been proposed and, in some cases, implemented. Some of the more theoretical suggestions regarding deregulation and industry restructuring are discussed in the following section. The remainder of this section will deal with the new initiatives being taken or proposed for the industry; they essentially involve only tinkering with and adjusting current regulatory policies.

One of the major participants in the debate on regulatory efficiency has been the Federal Energy Regulatory Commission. Given its role in the industry and its responsibilities for the implementation of PURPA, the Commission's attitude towards the current problems in the industry and how they can best be solved is of paramount importance in assessing how the industry will likely develop in the future. The FERC appears to favour continued regulation, although tailored to the particular circumstances. The former Chairman Martha Hesse recently outlined the principles governing the appropriate form of regulation to include:[10]

1. the degree of regulation should mirror the degree of market power such that workably competitive markets

should be allowed to operate with a minimum of regulatory interference;

2. regulation should promote the development of competitive market structures; and

3. regulatory policies should create a general framework for economic efficiency.

This focus towards more flexible and market-oriented regulatory procedures appears to underlay the three Notices of Proposed Rulemakings (NOPR) issued by the FERC in March of 1988.[11] These notices are the culmination of 3 years of intensive groundwork, public inquiries and regional conferences concerning the electric utility industry and the impacts of PURPA. As such, they signal the intent and direction of future FERC regulations and guidelines. The follow-through to these three notices could force substantial change on the industry. The first two proposed rulemakings concentrate on making reforms on what is permissible under PURPA while the third attempts to streamline regulation under the Federal Power Act.

The first FERC rulemaking relates to the administrative determination of avoided cost. In its rules to implement PURPA, the FERC stated that the prices paid to any QF should be consistent with the purchasing utility's avoided cost. The payment of rates greater than avoided cost could lead to an undesirable subsidy of QFs by rate payers because of higher retail rates, and could also displace the use of more efficient non-QF sources. On the other hand, the payment of prices less than avoided cost could result in the displacement of QF sources by less efficient sources. It would also be in conflict with one of the stated purposes of PURPA: to encourage the maximum amount of QF capacity consistent with rate payer indifference.

The FERC still subscribes to the appropriateness of paying rates consistent with full avoided cost but recognizes that the implementation of this on the state level has led to some unforeseen definitional and operational difficulties. Hence, this first rulemaking proposes several new guidelines and regulations to clarify avoided cost determination in order to alleviate some of the difficulties and inconsistencies that have arisen. Some of the more important proposals in this rulemaking are:

1. states are prohibited from setting rates greater than avoided cost for any reason (such as development incentives);

2. capacity payments to QFs are not required once the utility has satisfied its capacity requirements;

3. avoided cost estimates must be based on the utility's least-cost alternative which has the desired characteristics. In other words, the utility's requirements with respect to availability, reliability, dispatchability, etc. must be taken into consideration when determining its least-cost alternative. All power is not the same and the rate paid must reflect its value to the utility;

4. the states must explain in writing exactly how the rate was derived, what factors were considered and how the individual factors were weighed; and

5. standard offers must be made available to all QFs of 1 megawatt or under in size, an increase from the previous cutoff of 100 kW.

These particular provisions and the more detailed ones contained in the NOPR are designed to simplify the determination of avoided cost and reduce some of the regional inconsistencies. Even with these additional guidelines, the proper determination of avoided cost using administrative procedures remains a complex and difficult task. As a result, a second rulemaking was issued to allow the implementation of competitive bidding schemes as an alternative method for determining QF rates under the assumption that such schemes, if properly designed, would yield a price consistent with the avoided cost associated with the least-cost option available to the utility.

This second rulemaking would allow the states to implement, if desired, a competitive bidding program for capacity. As envisioned, the state commission could determine a specific block of required capacity that would be open to bidders; it may encompass all or part of the utility's total needs. The quantity and quality of the capacity, criteria for participation and selection and the purchase terms and conditions must be well publicized in advance. In order to determine the least-cost alternative open to the utility, the program should be open to all potential suppliers (termed all-source bidding) including the utility itself. If potential sources are to be artificially limited, the state would be required to use the excluded sources to set an initial benchmark or price cap. If other factors besides price are to be considered in the selection of the winning bid, each must be explicitly specified and some method of quantifying and aggregating such factors must be established. The state commission would be required to verify the winning bids and the winners must be held to their bid price.

While a bidding scheme may promote competition in the generation of electric power, the FERC views the schemes primarily as an alternative way to determine avoided cost while still meeting the goals of PURPA. If a utility is required to purchase power on a first-come basis, it will only be by chance that it purchases from the most efficient sources. The use of a bidding mechanism would allow the suppliers to be ranked according to economic criteria, promoting an efficient use of resources and equitable rates for consumers. It would not alter the existing encouragement for QFs and cogenerators, although an all-source program does open up the field to other types of facilities. It would also allay some concerns that PURPA has altered the type of facility constructed at the expense of economic efficiency.

The FERC delayed any introduction of a rulemaking relating to transmission access issues which may arise with the introduction of a competitive bidding mechanism. The Commission's understanding of PURPA is that the Act requires non-discriminatory treatment of QFs within a specific market but it does not require that a competitive market for QF sales be established. Therefore, the Commission does not believe that transmission access is required along with a bidding scheme in order to satisfy the goals of PURPA.

The FERC did raise one question regarding transmission access, however, in conjunction with a utility's participation in all-source bidding schemes. At times, such participation may require special provisions on transmission service to ensure the utility does not block the participation of others. The Commission asked for opinions concerning mandatory "wheeling in" and "wheeling out." "Wheeling in" arises when a utility bids to supply another utility's capacity. If its bid is unsuccessful, the utility is required to provide transmission service to the winning bidder if necessary. This prevents the utility from blocking the participation of others with the claim that it has insufficient transmission capacity to transfer power from the ultimate winner to the purchaser. "Wheeling out" occurs when a utility bids to supply its own capacity. In this case, it must provide wheeling services to any unsuccessful bidder who wishes to sell to an adjacent utility.

The separation of the broader transmission access question from the proposed rulemakings has been quite controversial. Many believe that the various problems facing the industry cannot be dealt with in isolation and that consistency in regulatory treatment requires the issues be handled simultaneously.

The third proposed rulemaking appears to address some of the unintended consequences of PURPA and a potential regulatory oversight relating to independent power producers (IPP). An IPP is a non-utility power producer which does not qualify, for one reason or another, as a QF or a cogenerator and which meets the following criteria: has no significant market power, owns less than 50 percent of the transmission facilities required to move its power to the buyer, and has no retail sales. Since they do not qualify under PURPA for special treatment, they are subject to full regulatory review under the Federal Power Act and PUHCA. This regulation includes certification, cost-based accounting and record keeping procedures, and the filing of rates with the FERC which are judged to be "just and reasonable" according to the Commission's current cost-based pricing procedures.

The fact that IPPs are subject to full regulation under these two Acts has had a chilling effect on the development of this sector, as the compliance costs of full regulation are high. The preferred status for QFs and cogenerators has resulted in the modification of IPP projects in such a way as to insure qualification as a QF. Some of these alterations distort the investment decision away from the economic choice that would have been made on the basis of cost and efficiency considerations alone. The result is a bias away from the most efficient use of resources.

The FERC does not believe that the use of full regulatory procedures and cost-of-service regulation is necessary if the regulated entity lacks significant market power. Therefore, the third proposed rulemaking attempts to avoid distortion in investment decisions and tries to encourage the development of IPPs by considerably simplifying and streamlining their regulation in order to reduce the cost of compliance. While it cannot exempt these producers from state regulation, the proposal will exempt them from federal accounting/record keeping practices, provide for advance certification, and allow for the filing of rate schedules without detailed cost support data. Unlike QFs, the utility would not be required to purchase from IPPs. The rates paid to IPPs, however, would be set through negotiation using full avoided cost as a ceiling. Alternatively, the price could be determined through competitive bidding. Both procedures are likely to determine a rate which can be considered "just and reasonable" according to current FERC criteria.

The Commission has indicated that it does not believe that major electric utilities necessarily have significant market power in jurisdictions outside their individual franchised service area. In this case, there is no reason why a utility should not be able to participate as an IPP outside of its service area. However, in order to prevent a utility from using its existing customers to subsidize non-regulated sales, the FERC has proposed a two-part definition of an IPP. The first part defines an independent power facility as "all or part of a facility not in the utility's wholesale or retail rate base and not otherwise cost-of-service regulated." The second part defines an IPP as an entity involved in a wholesale power sale from an independent power facility which lacks significant market power and where the buyer is not in the seller's retail service area and is not served by essential transmission facilities owned by the seller. An IPP qualifying under this definition would be allowed to take advantage of the streamlined regulatory procedures.

The above NOPRs indicate the direction that the FERC is considering taking in relation to QFs, cogenerators and IPPs. The FERC is also allowing some experimentation in bulk power markets as a prelude to addressing the question of transmission access and pricing. The importance of these experiments is intertwined with the concepts of utility coordination and wheeling.

Coordination activities between and among utilities are undertaken in order to reduce the total cost incurred by any one utility in meeting its future and existing demand. This is done via the reduction of operating costs and/or the conservation of resources. There are, conceptually, two primary types of coordination activities--those undertaken for economy purposes and those related to reliability considerations. One example of the latter is the sharing of reserve capacity. In a coordinated system, an individual utility will not require as much reserve capacity to cover unanticipated and anticipated contingencies as it can also rely on its partners' reserve capacity should it be required.

Resources can also be saved with coordinated planning of new capacity. For each individual utility, demand may grow slowly or in small increments relative to the economic size of a generating unit. If the utility builds the new unit on its own, it may have significant excess capacity for several years until its internal demand increases sufficiently. If several utilities build the unit, however, the combined demand increase will increase the utilization of the unit and reduce excess capacity. This practice can also lead to the development of more economic generating sources first.

Economy coordination activities generally refer to economy energy interchanges or bulk power transfers. The costs to any one utility can be reduced if it can purchase power from another utility at a price below what it would cost the utility to generate the power itself. For example, two utilities may have peak demands which occur at different times and they can purchase from one another during peak as an alternative to running their most expensive units. Also, one utility may have, for example, excess hydro power for sale which could be purchased by a utility whose option is to generate from a higher-priced fuel source. The savings accruing from coordination can be substantial--one recent estimate indicated a savings of around $15 billion per year across the U.S., 75 percent of which came in the form of capital savings and 25 percent due to economy interchanges.[12]

Economy interchanges or bulk power transfers have grown significantly over the last 10 years and it is these transfers to which the FERC authorized experiments are directed. The FERC is interested in promoting such transfers but certain barriers exist that inhibit increased interchange. The most important of these is the transmission system and the pricing of this service. Since transfers can be beneficial between non-adjacent utilities, increased bulk power transfers can depend crucially on the rates charged for the wheeling of power across third party facilities. The price at which the power is sold and the rates charged for transmission services are both regulated by the FERC.

The first large scale experiment, authorized by the FERC in 1983, was the Southwest Bulk Power Experiment involving six diverse generating utilities in Arizona, New Mexico and West Texas. The primary purpose of this experiment was to determine the impact of current FERC pricing practices on the volume of bulk power transaction; that is, it was designed to test the impact on short-run efficiency and competition. The FERC has regularly approved prices for bulk sales which are equal to the seller's marginal cost of producing the electricity plus an incentive provision. This can be either a "split-the-savings" provision such that the price is midway between the seller's cost and the buyer's cost of self-generation, or a percentage adder (limited by the FERC) to recover unquantifiable costs. This pricing procedure was altered to provide a wide band within which the utilities could negotiate a price which the FERC would accept as "just and reasonable." This band ranged from a little under 1 cent/kW.h to over

9 cents, wide enough that it would be unconstrained by regulatory considerations. The transactions covered by the pricing procedure were limited to economy energy (transactions less than one month in duration) and block energy (greater than one month).

Usually, the FERC requires that all of the profits realized from such "wholesale" sales must be passed through to rate payers. This was reduced to 75 percent for the experiment, thereby, allowing 25 percent to accrue to shareholders, if desired, in order to increase seller participation in the project. The FERC also wanted to insure that individual utilities could not use the transmission system to thwart sales between other utilities, requiring the existence of non-discriminatory open access. These transmission services could be provided according to existing contracts or for a flat fee per kilowatt-hour[13] regardless of the distance or path travelled. Finally, the utilities chose to conduct the experiment through bilateral negotiations rather than setting up a formal information exchange mechanism to acquaint buyers and sellers with trade opportunities.

This experiment lasted 2 years although, because of its limited scope, only the first year results were analyzed in detail. Several different techniques were used to evaluate the efficiency aspects of the experiment but the results were mixed. Some techniques showed modest gains while others showed little. The results for competition aspects were more positive. The analysis showed that although the market is not naturally "structurally competitive" because of the high concentration in the industry, this did not necessarily result in the exercise of market power. Rather, because concentration existed both among buyers and sellers, the net effect was a sort of cancellation so that the price at which the transactions took place may not have been that different from the price which would have prevailed in the absence of market power. The general conclusion was that while the prices were quite different than what had been expected with competitive conditions, the market did become more competitive.

The limited scope of the first experiment led the FERC to authorize a more ambitious project in 1987. Covering a 2-year period (that will likely be extended), this experiment involves the Western Systems Power Pool (WSPP), a group of 15 utilities covering a 10-state area which are largely connected by ultra-high voltage transmission lines. These utilities, in aggregate, are responsible for around 80 percent of the generation in the western U.S., making this second experiment considerably larger than the first.

The difference in the two experiments goes beyond just size. The first experiment involved trading economy energy only: this second test expands the range of power services to include short-term firm capacity. More significantly, however, the WSPP Agreement allows transmission services (nonfirm, standby and firm) to be treated as a commodity and priced flexibly. In the previous smaller test, transmission services were priced according to the usual embedded cost principles which generally results in prices below the true value of the transmission service to the participating utilities. Hence, little third party wheeling took place. The goal of the WSPP experiment is to determine whether transmission access and flexible, efficient pricing, coupled with formal information exchange, will lead to a more efficient utilization of the existing system.

As in the previous test, the power services covered in the Agreement could be priced anywhere within a broad band, the ceiling of which is determined by the highest pool-wide costs. While rates within this band will not be subject to FERC approval, the Agreement poses extensive reporting requirements on the participating utilities. Transmission services may also be set within a wide band--in the first year, the minimum price was set at 0.1 cent/kW.h while the maximum was 3.3 cents. The actual price set by a utility would be based on the perceived value of the service at the time it is offered. In other words, the prices should reflect the alternate uses of the transmission line, the value of these alternatives, the risk of committing the lines to the purchaser, and the type of service available for sale. In order to facilitate exchanges among the parties, a formal informational gathering system for prices and available services was created. Although no results have been forthcoming as yet, this experiment should provide valuable insight into the impact of pricing regulation on power service exchanges and, more importantly, on the availability of transmission services from third parties.

The FERC is not the only participant in the electric utility industry to encourage and initiate new, experimental procedures. One of the first, similar in some respects to the bulk power experiments, was the Florida Energy Broker. This was largely instituted as a means to reap some of the operating cost reduction benefits arising out of pooling arrangements without requiring joint operation and planning. A brokerage system was created whereby participating utilities report the price at which they are willing to purchase or sell a block of power. The price is based on the particular utility's cost of self-generation. For example, a purchasing utility will determine its cost to generate the required power. As it is only advantageous to buy if the price is less than this, it will put in a bid price somewhat lower than its internal cost. On the other hand, the selling utility will offer its power at a price somewhat higher than its self-generation cost.

The broker in the Florida system matches the various buyers and sellers. The highest purchase price is matched to the lowest selling price and the gains from the trade are split evenly between the two participants. The second highest purchase price is then matched to the second lowest selling price and so on until the difference between the remaining offers is too small to warrant the transaction. The cost of wheeling power is also considered in the calculation. There is an allowed range of prices for wheeling services but, in general, the fee is small. These rates are published in advance and are calculated on a postage stamp basis throughout the state.

The highest-to-lowest matching system is designed to create gains in efficiency by substituting production from more efficient, lower cost plant for that from higher cost plant. Large efficiency gains have undoubtedly been achieved relative to the previous arrangement but it is unlikely that all efficiency gains have been realized. Further improvements could be forthcoming with the use of a market-clearing price rather than the split-the-difference procedure.

The States have also been very active in the implementation of competitive bidding schemes; in fact, the involvement of many states predates that of the FERC. As of mid-1988, there were six states with formal programs in place and another seven which allowed solicitation without formal rules. The single utility with the greatest amount of experience with the program is Central Maine Power, while Massachusetts has the largest number of participating utilities. Several other states have bidding schemes proposed or pending.

As the impetus for these schemes has been on a state level, the actual programs in place vary a great deal. In general, however, the block of capacity required is determined by the utility and the regulatory commissions and all use a sealed bid procedure. Some of the states allow conservation and load management schemes to participate. One such state is Maine. If a customer installs conservation equipment and/or practices and can quantify the resulting load reduction, the customer is entitled to be paid the avoided cost on this reduction, even if this exceeds its incurred costs. Some of the states require wheeling while others do not. In most cases, there is an exemption for which small QFs and independent producers under a specific size may apply because the compliance costs for such producers would be relatively large. These producers are allowed avoided costs payments under the exemption.

A competitive bidding scheme can be superior to traditional regulatory practices. It can provide increased supply options for utilities, reduced risk for ratepayers and a stronger incentive to control cost. It also increases the chance of picking the efficient over the inefficient relative to some of the alternative arrangements such as first-come first-served. These schemes may also be superior to another common method of securing third-party capacity--standard offer contracts. These offers require a determination of the prices, terms and conditions that will elicit an efficient response from willing suppliers. The bidding procedure concentrates on determining the appropriate quantity of capacity required and allows the bidding mechanism to determine the corresponding prices, terms and conditions. The task involved in the latter procedure is likely to be less subject to forecasting error. This reduces the risk of buying an inappropriate amount for an inappropriate price.

While competitive bidding schemes may be superior, there are many factors that must be considered in the design of a scheme that will promote competition and efficient resource use. Its success will depend partly on the design and partly on the number and type of bidders that are forthcoming. A small number of bidders will not provide a competitive environment.

The design of a successful bidding scheme is not a simple task. It must be structured to prevent strategic manipulation by the participants and to provide incentives for the bidders to meet the terms of the bid and the resulting contract. Often there will be more capacity offered than required but not all winning bids come to fruition. There should be some method of testing to ensure the bidders are qualified producers. Safeguards against price fixing, collusion and market share rotation among participants are required. It is possible for some participants to put in artificially low bids in the hope of forcing higher payments at a later date once the utility is dependent on the capacity. There is also potential for opportunistic behaviour on the part of the utility, ex post, since once the capacity is built, the investment is sunk and the assets are not readily adaptable to alternate uses. This is part of the reason why a long-term contract is preferred.

There are a myriad of other decisions which must be made in the development of a workable scheme. The capacity required by a utility generally has given characteristics and factors other than price--dispatchability, maintenance, reliability--should be considered in determining the winning bid. The weightings and ranking procedures must be created. Contract terms and conditions, including length, escalations and guarantees must be set forth.

In all of these considerations, there must be a trade off between rigid self-scoring rules and flexibility to adapt the rules to individual situations. A rigid set of rules may be optimal in certain circumstances but the resulting contracts are not likely to be optimal over a wide range of participants, situations and times. The price structure and level for each bidding project that will promote efficient decisions and resource utilization are likely to vary. This is very difficult to quantify in any clear, precise and unambiguous way. The variety of schemes being implemented at the state level can be an invaluable source of experience and empirical verification to provide direction on the above questions and concerns.

D.6 Further Regulatory Alternatives

Any discussion on the restructuring of the electric utility industry or adjusting the framework of its regulation must be based on a set of well-defined objectives for the electric system and what it provides as well as a clear understanding of its current strengths and weaknesses. The most commonly stated objective in this regard is the provision of a reliable supply of electricity at the lowest possible cost. Behind this statement lies the concept of economic efficiency. One of the initial rationales for the regulation of the industry was that it was a natural monopoly and a firm with this type of market power would reduce quantity and increase price relative to the price and quantity that would arise in a competitive market. Regulation was instituted to provide a competitive outcome--the efficient allocation of resources--in a market which would not provide this outcome naturally.

An efficient allocation of resources implies the provision of the "correct" levels of supply and reliability at prices which lead to cost-effective utilization decisions both in the long run and in the short run. Marginal cost pricing accomplishes this by assuring the value of the resources put into the provision of electricity is equal to the value society places on the end product. The concept of efficiency also applies to risk--it should be allocated to those who can bear it and who have the most control over it.

Regulation, to date, has not been particularly successful at achieving this objective. The current system of administratively determined processes and decisions is necessarily slow, cumbersome and backward looking. Its inherent slowness to change has made it inadequate in some cases to deal with issues arising in a dynamic changing industry. Various policies and procedures have caused distortions in the market place. Rate of return regulation can induce overinvestment in times where the allowed rate of return exceeds the firm's true cost of capital and underinvestment when it is less than the true cost. Both scenarios have occurred in the last few decades. Regulation and the protected status of utility markets can erode the incentive for a firm to be efficient, an incentive which is often provided by competition. The passage of legislation such as PURPA has distorted investment decisions towards favoured technologies and facilities; such decisions are based more on administrative fiat than economic forces. The limitation of markets to state political boundaries or smaller areas does not necessarily imply the efficient market size that would result from a natural, spatial equilibrium. The inherent subsidization of publicly-owned electric utilities and their preferential pricing policies has likely expanded their market size and resource allocation to levels beyond that which is optimal and efficient.

Perhaps the greatest failure of current regulatory practices is in the area of pricing. Current pricing policies are largely based on historical embedded average costs rather than marginal costs and can result in perverse outcomes that do not reflect market conditions--such as rising prices at a time of excess capacity. Further, cross-subsidization among customer classes and groups is common. The initial rationale for existing pricing policies may no longer be relevant. When regulation was first initiated, the industry was experiencing economies of scale such that marginal costs were less than average costs. Pricing on a marginal basis would result in a total revenue that would not cover total costs. As much of the property was privately owned, some method to cover the deficit was required. Given the lack of alternatives on a political level, state or local authorities turned essentially to average cost pricing to insure cost recovery. There are indications that within today's industry, marginal costs exceed average cost. Hence pricing at marginal cost is now possible but the slowness of regulatory practices to change has resulted in sub-optimal prices which send out incorrect signals and result in inefficient utilization and investment decisions.

Critics of the current regulatory situation have offered several suggestions--ranging from introducing more competition through to total deregulation of the industry--all of which are primarily aimed at improving economic efficiency in the supply and use of electricity. The basic premise of much of this input is that increased competition from within the existing regulatory framework or from its partial or total abandonment is more likely to insure economic performance and efficiency gains than are current regulatory procedures. Experience with other industries that have been taken along the deregulation route indicate several potential results: increased price competition, restructuring of firms and mergers/acquisitions, the unbundling of services and prices, and changes in the quality and reliability of service.

Each of these outcomes has raised a debate on potential advantages and disadvantages. Some note that increased price competition may mean increased prices, especially in the short run, while others maintain the net result will be a lower cost supply system in the long run. The debate on mergers and acquisitions also has two sides. Many fear the result will be a small number of large firms which will reduce overall competition. Others note that many of the existing utilities are now sub-optimal in size because of market suppression by state regulatory authorities. The merger of some of these utilities will allow for greater efficiency through the tapping of economies of scale, and such. To many, the unbundling of prices and services is inevitable and desirable. Cautionary voices remind, however, that the unbundling often results in selective price competition concentrated in high volume, price elastic service which can be considered *"creamskimming."*

The most heated debate tends to surround the question of changes in the quality and reliability of service. Many assert that the industry today provides high quality, very reliable service and any change that occurs is likely to be downward in direction. Unbundling can identify the costs associated with various levels of quality and reliability and will allow consumers to choose the level that suits their needs. There is no way to know if the current levels are optimal and what value consumers actually place on reliability and quality as they are never given a choice. This leads to the question of whether a certain level of service should be imposed on the public if that same public would not pay the implied cost if it was free to make a choice. Supporters of the current system argue that success should not be tampered with unnecessarily.

On a broader perspective, there are voices in the electric utility debate that advocate caution. Deregulation may not be symmetric; that is, once the industry has been taken apart or changed, it may not be possible to return it to the initial structure. Total deregulation raises some serious questions with respect to reliability and the universality of service that cannot be dismissed lightly. Partial deregulation can provide valuable insights into the deregulation process before the process is too far advanced to stop. It has been noted that many of the benefits of deregulation can be achieved and the economic efficiency of the system improved without making any fundamental changes to the existing industrial structure. This is the case in wholesale markets and especially in the area of pricing. A movement towards marginal cost prices that reflect replacement costs to society rather than sunk costs will result in large efficiency gains but requires little in terms of changes from the current environment.

The electric utility industry and the electric system itself are complex, complicated entities and the arguments behind the concerns discussed above are no simpler. These arguments are explored below but for ease of presentation, they are divided into those relating primarily to the distribution phase of the industry, those concerned with issues in the generation sector, and those fundamental to transmission issues.

D.6.1 Distribution

The distribution function of the electric power system involves the delivery of electricity at retail prices to the ultimate end user or customer. Since it is the retail price which provides consumers with the signal on which they base consumption decisions, it is in this sector that large efficiency gains can be realized with a movement towards marginal cost pricing concepts within the existing regulatory framework. These efficiency gains may be limited at first because short-run consumption decisions depend heavily on the existing stock of appliances and/or equipment. In the long run, however, as investment decisions to replace equipment are based on marginal replacement value, the gains will increase.

Most of the suggestions regarding the direction in which the electric industry should evolve recommend retaining extensive regulation over the distribution function. This part of the industry still exhibits many of the natural monopoly characteristics that initially led to regulation. Customers must still be physically linked to the supplier's network and competition among suppliers is likely to result in unnecessary duplication of facilities. Even if the sector was open to competition, it is not clear that there would be a sufficient number of interested parties to provide a competitive market outcome. Deregulation could simply mean trading a regulated monopolist for an unregulated monopolist (or oligopolist). Significant market power will still reside with the firms and exploitation of consumers is likely. Beyond the question of anti-competitive pricing, total deregulation could lead to the curtailment or cessation of service to particular customers. Given the importance of electricity in today's society and the lack of market power on the consumers' side, deregulation of the distribution function is not likely nor particularly desirable.

While total deregulation is not often called for, partial deregulation--or rather total deregulation for a given subset of customers--is often advocated. This proposal would allow large retail customers to "shop around" among various power producers and purchase power at the lowest possible cost. This is often termed "competition" when in reality it is simply a movement induced by regulatory distortions rather than true competition induced by differences in prices that reflect economic costs. In other words, the desire to shop around arises because of spatial differences in regulated prices that reflect the cumulative effect of past administrative decisions and accounting procedures, rather than the replacement value of resources. Prices vary among utilities and the retail customer responds to a change to reduce his costs by moving to what is perceived to be a lower cost producer. Since prices do not reflect true economic costs, this is not necessarily the case and the change in suppliers will not always increase efficiency or result in a more efficient allocation of resources.

Beyond the fact that it may be inefficient, allowing large customers to shop around can create a whole host of other difficulties, distortions and costs. Much of this argument relates to the obligations of the utility and its retail customers. In return for its franchised monopoly, the utility has the obligation to provide reliable, low cost service to all who request it. This obligation extends from meeting the customers' current needs to providing for their future requirements. To this end, the utility expends resources to secure these supplies. The customers' "obligation" is to purchase their requirements from the local utility and to reimburse the firm for expenditures made on their behalf.

In the absence of any other changes, if the local utility's price is too high, the large customer decides to change suppliers. In its obligation to serve, the initial utility had built sufficient capacity to meet all requirements including those of the departed customer, some of which is now excess capacity. The utility's revenues fall. Operating costs fall since the customer's requirement no longer needs to be generated, but this may not offset the fixed cost associated with the capacity which is now idle. If it does not--resulting in what is termed stranded investment--the remaining cost will be borne by the customers still on the system. This will result in increased retail prices which in turn increases the incentive for others to shop around and the incentive for self-generation. The latter leads to more large loads or customers leaving the system.

The problems associated with bypass of the local utility--either through shopping around or self-generation--do not necessarily end with stranded investment. If the prices charged by the new supplier rise, the customer may decide to return to the initial host utility. This utility may no longer have sufficient existing capacity to meet the returning load. New capacity may have to be provided and, if retail prices are still determined on an average embedded cost basis rather than on incremental costs, the other customers on the system would end up paying the difference in the two. This amounts to subsidization. It also raises the question as to which utility should bear the obligation to serve the customer and include his potential demand in its load forecast. Significant resources are required to build future capacity requirements and mistakes can be very costly to society, the utility and its customers. Shopping around makes the long-term forecasting upon which these plans are built even more difficult and increases the uncertainty and difficulty associated with least-cost planning. Furthermore, the ability to shop around, in order to be successful, would require mandatory access to the transmission facilities and wheeling by the local utility. In addition to the general problems relating to mandatory wheeling (discussed later), it gives rise to the question of who is responsible for maintaining the reliability and integrity of the customer's power supply--the generator or the wheeler? The logical extension of this proposal could result in the utility's franchise being eroded without corresponding relief in its obligation to serve.

While many of the questions raised do not possess easy or obvious answers, other problems are less intractable. The revenue lost by the initial utility can be recouped through a wheeling charge equivalent to the (net) revenue loss. This will only promote economic efficiency, however, if the customer is changing suppliers in response to marginal cost differences. Another solution is to allow the customer to choose the local utility or an alternate supplier but prevent switching back and forth unless the full incremental transition cost is paid. The obligations and costs imposed on either utility would be limited to those negotiated in the customer's contract.

This discussion demonstrates the inconsistency between retail competition, traditional ratemaking practices and the traditional concept of the obligation to serve in the distribution sector. While increased competition or deregulation within the sector may not be appropriate, there have been suggestions that this function be separated from the others. This envisions the creation of "discos" or pure distribution companies spun off from existing vertically integrated utilities. The discos would retain the obligation to serve and would be responsible for contracting sufficient capacity and energy to meet retail customer needs. This scenario has two variants. One would involve mandatory access and wheeling across transmission facilities, allowing the discos to shop around. This structure would not have the above obligation-to-serve problems associated with shopping around, but there would be difficulties relating to mandatory access. The second variant would involve the creation of "transco/discos" where the ownership of transmission facilities would remain with the distribution firm.

The separation of distribution from generation, and possibly transmission, can have some advantages. It may result in increased financing and contracting flexibility for the disco which could ultimately reduce the price to consumers. Further, as capacity is contracted for, rather than built and operated, some of the risks associated with construction and unit performance are shifted away from the ratepayers to those who have more direct control over the risk. This, of course, depends on the contract negotiated. The discos would be able to develop a portfolio of contracts that minimize overall risk. There would be an incentive to pursue all economic conservation and demand side techniques.

There are also disadvantages with this scenario. The most immediate would be the enormous difficulties associated with financial reorganization and divestiture. There are many complex issues, but two are worth mentioning for illustrative purposes. First, all of the property and resources of the vertically integrated utility must be allotted to the various functions and the costs associated with each identified. There is no easy or unambiguous way to allocate common costs. Even if this problem is solved satisfactorily, once done, the distribution portion must be purchased. Over the years much of the capital and equipment have been depreciated and paid for by ratepayers. If sold, the stockholders of the firm would reap a windfall gain, likely at the expense of consumers.

Even if all such difficulties are solved to the satisfaction of all participants, other problems remain. With little or no ownership of generation/transmission systems,[14] the regulatory responsibilities of state commissions will decline. The costs incurred by the disco will be largely determined by the contracts it negotiates. Consequently, the regulators will have a keen interest in the prices, terms and conditions. Their power for cost disallowance can result in limited negotiating ability for the disco which would simply serve to extend the regulatory reach into the unregulated sectors of the industry. This would negate many of the benefits for which deregulation was introduced. On the other hand, an assurance of simple pass through of costs would leave the regulatory authorities powerless to insure that the disco tries to negotiate the lowest price possible. It would simply portion the costs among ratepayers without being able to insure that the prices paid by them are the lowest possible under the circumstances.

Difficulties with respect to reliability and security of supply may also arise. As the distribution firm has given up its ownership of generation facilities, it has no method of guaranteeing that the power will actually flow. It has no control over unit performance nor can it prevent the owner of the facility from stopping production if that is the most economic decision. Some of these aspects will be covered in the contract but it is impossible to design a contract to cover all possible contingencies. The financial payment arising from breach of the factors will not immediately replace the electricity required. Currently, this aspect is handled in the vertical structure of the utilities and replacing corporate interrelationships with contracts will not be easy.

One related point in this regard involves reserve requirements. A utility generally has some capacity in reserve to allow for maintenance and unanticipated outages of other operating units. When generation and distribution are no longer within one corporate framework, it is unclear who would be responsible for providing this reserve--the generator who supplies the power or the distributor who purchases the power. In either case, overall reserve requirements may rise to compensate for the reliability difficulties faced by the disco or because each generator supplies his own reserve, losing the current advantage of shared reserve across several generating units.

D.6.2 Generation

As with distribution, there are various proposals to change the traditional framework in which the generation of electricity takes place. These can be conceptually divided into those which would increase competition within the existing framework and those which would totally alter this framework through deregulation. There is, of course, some overlap as the logical extension of the former could lead to the latter. Hence, many of the advantages and disadvantages apply to both types of proposals. There are also insights into the impact on distribution utilities discussed in the previous section.

Of the proposals advocating change from within, the most common is increased competition in the provision of new capacity. Competitive bidding schemes are one example. The basic premise of this scenario is that a utility would identify its future capacity needs and the characteristics of that capacity.[15] Rather than building generation capacity itself, the utility would open the process to bidders. In some cases, the utility would be able to bid on its own capacity. Taken to its logical conclusion, over time the retirement of existing capacity would result in all capacity needs being met in this manner.

The benefits of this type of system could be substantial. If all sources were allowed to participate without regard to ownership, size, fuel type, etc., the distortions caused by legislation like PURPA would be avoided. The utility would have a broader range of sources than currently and a greater chance to serve its customers as efficiently as possible. Competition among sources would provide an incentive for all to behave efficiently, providing a lower cost power supply in the long run and, ultimately, lower rates to consumers than might have been the case otherwise. Pricing for capacity and energy would reflect current costs and would be based on the marginal costs of all, not just the utility. Expansion of the system would be justified on market efficiency grounds and there would be a market test for new technologies. Contracting with third parties would transfer part of the risk from ratepayers, would likely improve the utility's financial position and could eliminate some of the current constraints on capacity construction. Finally, capacity additions could be added in smaller increments to more closely match the growth in demand, reducing problems of temporary excess capacity. It must be remembered, however, that many of the above benefits rest on the premise that there would be many competitors willing to enter the market so as to provide the benefits from increased competition. It is unclear at this point whether the industry would be lucrative enough to attract sufficient entrants to make the market competitive, rather than oligopolistic.

Increased competition would likely provide additional benefits but there are some potential problems to consider. Not all of these difficulties are insoluble but the severity of the problem often increases as the proportion of the capacity included grows. One concern, similar to the distribution case, is reliability. Purchases from a third party reduces the control that the utility has over the construction of capacity. It is unclear what would happen if the construction costs were higher than anticipated by the bidder, making the negotiated contract uneconomic. If the capacity contracted for does not come on as required, how would it be replaced in the face of long construction lead times and at what cost? Conversely, if the demand falls and capacity is not required, the utility may be locked into purchasing unneeded power. Bidders may require long-term take-or-pay contracts in order to obtain project financing. The utility is the only participant with an obligation to serve and this may seriously limit its bargaining power in times when capacity or energy is short. Situations such as these could be quite costly for the utility and its ratepayers alike.

The utility may also lose control over the operation of part of its generating system. Owners of the contracted capacity may not be willing to relinquish control over the unit's operation since their revenue will be determined by how much the plant produces. The utility's load varies continually and it must operate its system to match the load variability. This means backing off or loading units as required. In order to keep the costs as low as possible, utilities practise economic dispatch where the cheapest units to operate are loaded first, followed by the increasingly more expensive units. If the utility is not able to control and dispatch the contracted capacity, it may have to purchase more expensive power at a time when cheaper units lie idle. The load following responsibility falls to the utility's own units which can lead to increased operating and maintenance costs and higher outage costs. Lack of operating control makes it more difficult to schedule maintenance of units in such a way as to minimize costs. Finally, it is difficult to insure that the contracted capacity delivers the performance levels promised. Many of these concerns can be addressed in the contract negotiated between the parties. This would essentially mean that the contracts will replace some of the benefits currently derived from vertical integration. The design and negotiation of such contracts, however, is not a trivial matter.

Leaving the construction of capacity in the hands of third parties also has ramifications for long-term least-cost planning and investment. Considerable savings in investment are possible by sharing reserve requirements across several generating sources. This becomes more difficult with several different owners. Currently, additions to the electric system of a utility are planned on an integrated basis--that is, for the system as a whole. What is optimal for one part, however, may not be optimal for the system in its entirety. For example, there can be a trade off between generation and transmission. It may be cheaper to construct a plant in a remote site because of, say, access to fuel supplies, but this would entail an increase in cost for the transmission facilities required to move the power to the load centre. When the utility has control over siting, it can make these comparisons and choose the least-cost combination. Without such control, it is difficult to plan a least-cost system of facility additions. It is also very difficult to do long-term forecasting and planning of transmission facilities without some indication of where the new generation sources are likely to be sited. Benefits from the coordination of these decisions within a single corporate structure may be lost.

Third party generation sources also make it difficult for a utility to assure the most efficient, cost-effective mix of plants to meet its requirements. The optimal size and type of generating unit depends on, among other things, economies of scale and system growth. If demand is growing slowly, it may be more economic to put in a series of smaller units to reduce temporary excess capacity. This must be balanced against the economies of scale present in larger units[16] which may sit idle for some time. In a rapidly growing system, however, large units may be the optimal choice. With third party generation, though, the utility's ability to exercise these options is limited. Furthermore, given the regulatory risks, long construction lead times (implying extended negative cash flows), and massive capital costs associated with large generating units, newly emerging power producers are likely to concentrate more on smaller units with lower capital requirements and a larger role for variable fuel costs. One benefit of smaller units is that they may reduce reserve requirements relative to larger units, since the reserve is generally of sufficient magnitude to replace the largest unit on the system in case of emergency shutdown or scheduled maintenance.

These difficulties (and potential benefits) apply equally to the proposals for deregulation of all generating sources--i.e., the creation of "gencos." Ultimately, this could lead to competitive bulk power markets where some combination of transco/disco utilities would "shop around" for their requirements among individual, independent generators. In this scenario, long-term, short-term and spot markets for power and capacity would likely develop. The current vertically integrated structure would be replaced by contracts.[17] The wholesale price of electric services would be marginal cost based and efficiency gains may result. However, unless the dichotomy in the treatment of public versus private is addressed, severe distortion in the market place will result from competition by subsidized publicly-owned utilities.

Total deregulation of generating sources is likely to give rise to additional difficulties beyond those already considered. Some will arise primarily during the transition to competition. Gencos can be created through complete divestiture or via subsidiaries of existing utilities. Both will have the allocation and windfall gain/loss problems mentioned previously. The creation of subsidiaries raises concern over the likeliness of arms-length negotiations between a utility and its subsidiary and the possibility of cross-subsidization between the regulated part and the unregulated part of the firm.[18] Moving to a deregulated scenario by distinguishing between new and old generation sources would create a two-tier regulatory system. Further, if the output from "old" sources is sold at regulated prices and the output from "new" sources is market priced, "creamskimming" may result.

One of the most often expressed concerns regarding deregulation in generation relates to the benefits of coordination and system integration. These benefits are analytically the same as those already mentioned for a single utility operating several generating units, except they arise from cooperation and coordination among utilities. Many utilities belong to a power pool whose structure can range from loose, informal arrangements to formal, detailed integration among members. To some extent, the benefits depend on the degree of integration present and are often proportionately higher for small utilities relative to larger ones. While the benefits may vary, they are by no means trivial.

Many of these benefits were discussed earlier but they bear repeating. Coordination can reduce operating costs of the members through economic dispatch and economy energy transfers. These savings accrue through fuel substitution--a utility with high cost generation will purchase from one with lower cost fuel supplies--and load diversity. In the latter case, periods of peak demand may occur at different times and one utility will buy from another at a price less than its own cost of generation from peaking units. With interchange among utilities, lower cost generation sources are utilized more fully and overall operating costs will fall relative to isolated individual systems. Operating reserve requirements for an individual utility will also fall if the members share their spinning reserve.

There can also be significant savings for member utilities in required capital expenditures. Installed reserve can be shared and maintenance schedules coordinated in order to reduce necessary reserve margins. Coordination in the planning and construction of a new plant can take advantage of economies of scale and allow a closer matching of load and capacity to minimize the cost of excess capacity from "lumpy" investment. Transferring energy among members can reduce the need to construct new facilities. Integration of systems can provide more siting flexibility, promote resource diversity, improve reliability by using other systems for emergency contingencies, and improve the quality of planning and operation through the exchange of information and ideas.

The success of integration and cooperation depends crucially on the exchange of information and the ability of members to agree on a common plan of action. Economic dispatch requires knowledge of each generators marginal cost. Long-term planning depends on the capital and operating cost of possible capacity additions. The identification of least-cost options requires information on retirements, forecasted demand and load growth, and data for load flow studies. Every power supplier must take an active part in the planning and operation of the system if the maximum benefits are to be achieved. This type of cooperation may not be forthcoming if generators are competing among one another for resources and customers. A lack of communication can result in incomplete analysis, uncertainty and a less reliable electric system. This is also a concern if just part and not all of the generation sources are deregulated. The new independent generators could join existing pools with the utilities but, with no transmission facilities or customers, they are likely to have different objectives than the minimization of overall costs. Further, the ability to reach mutually satisfactory decisions becomes more difficult as the number of participants rises.

If total deregulation causes a reduction in these benefits, the cost to electric consumers can be significant. The impact of more limited competition is likely to be considerably smaller. However, neither of these suppositions implies that the current system is optimal. Many of the existing coordination/cooperation mechanisms do not capture all of the efficiency gains possible. Improvements in this are related to transmission issues, which are discussed below.

D.6.3 Transmission

The most heated debates in the electric industry today centre on the transmission system because it is a crucial and integral part of the electric system. Reliable electric service requires that utilities cooperate in the operation of their generation and transmission facilities in order to provide frequency control, voltage support and stability. This cooperation is critical because, unlike natural gas, electrical energy cannot be directed along a particular path. Rather, it flows along the line of least resistance. Consequently, in a power transaction between two parties, the system of a third party can be affected by such "loop flows." Cooperation is necessary to keep all operating parameters within the technical and engineering limits. The transmission system is, therefore, relatively fragile.

Transmission is also one sector of the electric industry that still exhibits considerable economies of scale. It is less expensive to transfer large volumes of power across one high voltage line than it is to send the same volume over several smaller lines. Since it retains many characteristics of a natural monopoly and because of the cooperation and integration required, most observers in the industry agree that transmission should remain regulated in some fashion.

Just how it should be regulated and structured is the subject of great controversy. Many suggest that it be structured into large regional monopolies, interfacing between competitive generation sources and distribution firms. Ignoring the problems associated with corporate and financial restructuring, this scenario could lead to efficiency gains due to economies of scale as smaller systems are aggregated into a larger one. Control would be centralized, internalizing the ability to cooperate and facilitating the transfer of power regionally.

Some difficulties, however, remain. The transmission system is a crucial link between generation and distribution and it cannot easily be separated from either. It is often suggested, therefore, that transmission can be organized like natural gas pipelines--on a common carrier basis. Distributors would contract for supplies of power and would purchase transportation services on the transmission system. Even beyond the physical integration and operating dependencies required between the various parts of the system to ensure service interruptions are avoided, transmission lines are not like gas pipelines. The structure and location of the pipeline does not affect the location of gas reserves nor does it affect the volume of production in the field required to meet demand in an efficient manner, both spatially and intertemporally. The pipeline does not necessarily have a pivotal role in optimizing production as demand and production costs vary over time. In the electrical system, generation and transmission are joint decisions because the location of generation capacity is not predetermined. If the siting decisions are made individually, the least-cost system is not likely to result. It is difficult to plan future additions which avoid both bottlenecks and excess capacity when generation siting decisions are made separately. While these problems may not be intractable, their solution will require both innovative institutions and creative governmental policies, the type of which is not yet obvious.

Restructuring the industry and its various functions is not a necessary step towards improved efficiency, nor is it necessary to go that far in order to determine the kinds of problems and difficulties that may arise. Bulk power markets can be opened up or distribution companies can be allowed limited shopping opportunities. The ability to attempt any sort of limited experimentation relies to a great extent on what policies and procedures are adopted for the transmission system. It, after all, is the link between all parties and whether it will fulfill its function efficiently depends on how three key issues are resolved--access, pricing and siting. Of these, access is currently the most contentious.

Access is important because it allows power to be wheeled from one party to another over the transmission system of a third party, if required. It can promote the equalization of power costs across the grid. It can promote economic efficiency if lower cost producers are allowed to displace higher cost producers in order to reduce the total cost of meeting demand. It should be noted that increased access does not necessarily guarantee such outcomes. The ultimate result depends both on the basis and degree of access and how the wheeling services themselves are priced.

With a movement towards competition in generation and competitive bulk power markets, there are three main options for access to the transmission system.[19] By and large, the difference between them is one of degree. The first option is voluntary access which is, for all intents and purposes, the status quo. A utility cannot be compelled to open its transmission system to outside parties. The other parties must negotiate with the potential wheeler and offer terms and conditions which are mutually satisfactory. This process can work very well as indicated by the significant increase in bulk power transfers in recent years. There are also potential drawbacks. Intervening utilities can thwart efficient transfers of power in order to supply the purchasing market itself. Simply because it owns the transmission lines does not imply that it is also the lowest cost supply option.

The second option is "wheeling in--wheeling out" as a precondition to allowing a utility to participate in a competitive bidding scheme. The purpose behind this option is to prevent a utility from shutting out potential suppliers or bidders with claims of insufficient capacity. This particular option is directed more towards preventing the utility from exercising its monopoly transmission position.

The third option represents the other end of the spectrum. Mandatory access implies non-discriminatory access to all within the constraints of existing capacity. It does not guarantee that transmission services will be available for all those who request it, but it does prevent the utility from discriminating against certain third party producers in the allotment of existing capacity.

There are technical difficulties associated with increased wheeling and access and these tend to become more critical and binding the more complete the access. Supporters of the status quo note that the existing transmission system was not constructed to provide trade opportunities. Instead, given their franchised area and inability to search for customers, utilities have tended to size their transmission systems to meet their own needs in minimizing generation capacity requirements and insuring reliability. Some unused capacity is generally incorporated into the system to allow for emergency contingencies and the backing up of other generation sources and transmission lines. While transmission lines can be loaded near capacity, the reliability of the system declines correspondingly. It is by no means clear where the optimal balance is. Furthermore, the increase in bulk power transfers in recent years has increased the utilization of existing lines so that in some areas of the country there is no additional existing capacity available. Increasing the access of third parties will increase the demand for wheeling and can exacerbate existing tight situations or create new capacity shortages. Increased wheeling may require substantial investment in strengthening and reinforcing existing lines and investment in new capacity.

The impact of a wheeling transaction on a wheeling utility is not necessarily negligible and this can extend to adjacent utilities who are not part of the transaction. Loop flows occur because the electricity flows along the path of least resistance rather than along the contract path. This can reduce the transfer capability of the lines and may increase the losses on the system. Losses on a heavily loaded line can be several times the average if the line is loaded further. A change in flows will require a change in system operation to maintain overall reliability. Heavier loading implies increased technological complexity and a greater need for cooperation among participants. This can be of special concern as mandatory access is likely to subject the electrical system to a large number of inexperienced users who are not familiar with the intricacies of the system.

While increased access is likely to require new control systems and technology, this is not an insurmountable problem although the solution will not be costless. None of this, however, will provide an incentive for the owners and operators of the transmission system to insure adequate capacity. In order to ensure that the existing system is utilized in the most efficient manner and that new capacity is constructed when required, the transmission and wheeling services provided by the system must be priced properly.

The price charged for transmission services will not only determine, to some extent, whether the existing capacity is used efficiently, but it will also determine if future capacity is added at the optimal time and level and in an efficient manner. Correct pricing will encourage wheeling that results in the transfer of power at a rate which will reduce marginal costs across the grid.[20] Correct pricing will also provide a signal that new capacity is required and should be built.

With the monopoly characteristics inherent in the transmission sector, market-based pricing is not often advocated[21] as it could lead to exploitation. The other option is some form of regulated pricing. The current practice is to set prices based on the embedded cost of all of the transmission lines owned by the utility, including those built many years ago at a relatively low cost. While these prices are designed to recover the total cost spent, they often do not reflect the true cost of the wheeling service to the utility involved. Nor do they assign the cost to those parties responsible for incurring them. Further, as the rates do not reflect the value of the resources used, embedded cost pricing encourages a demand for wheeling which is at an uneconomic level. Finally, because the prices do not cover the incremental cost of providing the service, existing customers end up subsidizing new wheeling loads and there is no incentive to construct new capacity in order to facilitate increased wheeling. Any form of mandatory access to transmission lines at embedded cost rates will not increase efficiency or enhance competition; it will simply protect users from monopoly pricing on existing facilities.

It would be preferable on economic efficiency grounds to price transmission services on an incremental cost basis. The short-run costs of wheeling are primarily fuel costs and the opportunity cost of alternative uses (such as reliability or potential economy energy transfers). The fuel component is that required to compensate for the change in transmission losses. These losses will depend on the direction and level of the native (as opposed to wheeling) load and will vary with new generating units coming on line. As both losses and opportunity costs can vary over time and space, flexible pricing will be required since one rate will not be appropriate for all situations.

The incremental cost of providing transmission service also varies with the type of service provided. While short-run incremental costs are appropriate for short-term energy transfers, firm service may require an expansion of the network. Hence long-run incremental cost, which covers the cost of building new capacity, may be more appropriate for this type of service. This, of course, implies that transmission services should be "unbundled" to allow flexible pricing. This in itself will present some difficulties since the allocation of total costs to various types of services is somewhat ambiguous.

While the correct pricing of transmission services is crucial to providing an incentive to both wheel and build new capacity, advances in this area may become largely meaningless if new transmission capacity cannot be built. A major reason for pricing reform is to encourage bulk power transfers. In many regions, the existing transmission capacity is already fully utilized and further power transfers will only come about with the construction of additional capacity. The problem arises in the ability to site and construct this capacity. In fact, many observers point to this difficulty as being the most critical issue facing the industry today.

The problems associated with siting relate to the cost and time involved in receiving permission to construct a high voltage line, especially across multiple states. The right-of-way requirements are large but, perhaps more importantly, a significant length of time is required to obtain the licence. It is estimated that it takes almost as long to site and construct a major transmission line as it does to site and construct a large nuclear generating plant. This is primarily due to the multiple political jurisdictions involved. Permission must be received from all local and state authorities along the proposed route. Not only does this allow for increased intervention by environmental groups and other interested parties, but the perceived costs and benefits will vary along the route. For example, the benefits are generally long run in nature and may be concentrated in the area where the line begins and ends or they may be dispersed through the region. Many of the costs or negative aspects are likely to be felt sooner and at the local level. These problems increase as the number of jurisdictions involved rises. Some method of balancing the regional and local interests must be found in order to alleviate this bottleneck, or bulk power transfers will be limited to what can be accommodated on existing transmission facilities.

Footnotes

[1] Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry 1986 (Washington, D.C.: Edison Electric Institute, 1986), p. 8.

[2] Karen Nelson, Electric Utility Diversification, Congressional Research Service IB82060 (Washington, D.C.: Congressional Research Service, September 26, 1983), pp. 1-5.

[3] National Regulatory Research Institute, Non-Technical Impediments to Power Transfers (Columbus, Ohio: National Regulatory Research Institute, September 1987), p. 25.

[4] T. Ferrar, F. Clemende, and R. Uhler, Electric Energy Policy Issues (Ann Arbor, Michigan: Ann Arbor Science, 1979), p. 2.

[5] A. H. Ringleb, "Environmental Regulation of Electric Utilities," in Electric Power: Regulation and the Public Interest, J. C. Moorhouse, editor (San Francisco: Pacific Research Institute for Public Policy, 1986), p. 189.

[6] This Act was repealed in May of 1987.

[7] See also Paul L. Joskow, "Regulatory Failure, Regulatory Reform and Structural Change in the Electrical Power Industry," in Brookings Papers: Microeconomics 1989 (Washington, D.C.: The Brookings Institute, 1989), pp. 125-208.

[8] Lindsay Pfeffer and Associates, Inc., Emerging Policy Issues in PURPA Implementation, prepared for the U.S. Department of Energy under contract No. PEACO1-83-PE-70404 (Springfield, Virginia: National Technical Information Service, U.S. Department of Commerce, March 1986), p. v.

[9] Ibid, pp. v-vi.

[10] Martha Hesse, "The Regulatory Challenges Facing the Electric Utility Industry Today," in Proceedings of the American Power Conference, vol. 49, 1987, p. 5.

[11] Federal Energy Regulatory Commission, Administrative Determinants of Full Avoided Costs for Sales of Power to Qualifying Facilities and Interconnecting Facilities, Docket No. RM88-6 (Washington, D.C.: Federal Energy Regulatory Commission, March 16, 1988); Federal Energy Regulatory Commission, Regulation Governing Independent Power Producers, Docket No. RM88-4 (Washington, D.C.: Federal Energy Regulatory Commission, March 16, 1988); and Federal Energy Regulatory Commission, Regulation Governing Competitive Bidding Programs, Docket No. RM88-5 (Washington, D.C.: Federal Energy Regulatory Commission, March 16, 1988).

These rulemakings are still in the proposal stage pending input from interested parties.

[12] John Casazza, "Free Market Electricity: Potential Impacts on Utility Pooling and Coordination," Public Utilities Fortnightly, vol. 121, no. 4, February 18, 1988, p. 17.

[13] A demand charge was allowed for block energy.

[14] This assumes that at the very least, the generation sector of the industry is largely deregulated. Indeed, the desire to separate the various sectors of the industry arises from the desire to deregulate parts of it. Otherwise, the current vertically integrated structure is adequate.

[15] This is analytically the same as a separate disco letting out contracts to meet its requirements. Consequently, many of the advantages and disadvantages discussed below will also be applicable.

[16] There is, however, a limit to these economies.

[17] Whether vertical integration or the market (with contracts) is a superior form of market structure depends on the industry. The market is superior if orders are frequent or, uncertainty is not particularly important or is easily hedged against the transactions taking place are not complex, and asset specificity is not important. The further the deviation from these conditions, the more appropriate vertical integration becomes in order that these factors can be internalized.

[18] These considerations are equally applicable to a competitive bidding scheme, if a utility is allowed to participate in its own program.

[19] This discussion relates to seller access rather than buyer access. Some of these issues have parallels in the distribution side but the major concerns with buyer access have been discussed elsewhere. As a further observation, the imposition of mandatory access may increase the pressure for buyer access or bypass.

[20] It should be noted that if the retail price of wheeled power is set on an embedded cost basis, the "correct" pricing of wheeling services will not optimize the operation of the electric grid as long as there are significant differences in embedded costs, because the latter gives improper pricing signals. The effect of the embedded cost differences can be neutralized, at least to some extent, if revenue reconciliation pricing is used for wheeling services. This is a pricing structure which keeps the total revenue position of the utility whole.

[21] This refers specifically to the price of transmission services. It is often advocated, however, that the transmission entity in a vertically disaggregated industry acts as a clearing house for bids and offers from generation and distribution entities. This could entail significant resources for monitoring--somewhat like the stock market.

APPENDIX E

CANADIAN ELECTRICAL GENERATING PLANNING MODEL (ELGEM)

Appendix E

CANADIAN ELECTRICAL GENERATING PLANNING MODEL (ELGEM)

E.1 Description

ELGEM is a computerized, mathematical model developed by the Alberta Research Council for the Canadian Energy Research Institute in its major study of the Canadian electric power industry. The model provides a comprehensive analytical framework for studying the many issues facing the Canadian electric power industry in the 1990s. Of particular interest is the issue of whether or not national rather than regional system planning would yield significant benefits. For that reason, Canada is disaggregated within ELGEM into eight regions, with the Atlantic provinces treated as one region and all the other provinces treated as individual regions. As electric power sales to the United States are currently perceived as an important issue, the United States is treated as four potential market regions, in which Canadian power could compete.

ELGEM is a linear programming, optimizing long-term electric generating supply model. Electric power demand for each region forms part of the input data; hence exogenous to the model. Given the availability and costs of all perceived generating options, the model generates a capacity addition schedule that minimizes the present value of costs, covering the period 1987-2010. In this respect, the model follows the methodology of Rogers and Choudhury[1], rather than the myopic, decision rule, year-by-year approach used in the UEXGEN Model.[2]

Two constraints must be satisfied:

1. there must be enough dependable capacity to meet the forecast average load; and
2. there must be enough peak capacity to meet the forecast peak power requirements, plus a specified reserve margin.

The model has perfect foresight and therefore the results represent an upper limit on what can be achieved, given the conditions specified by the user.

The model has been implemented on a main-frame computer, using a user-friendly software package, MAGEN, developed by the Haverley Corporation. **The Alberta Research Council is prepared to run different scenarios developed by third parties. The latter may simply alter the data entries in a data input disk, already prepared in a Lotus 1-2-3 format. This disk can be made available to interested parties.**

E.2 Model Capabilities

The current database permits the generation of a reference or base case scenario. However, in view of both data and policy uncertainties, the main use of the model is to test various scenarios and assess comparative impacts. The model has been designed to permit the user to develop the following scenarios:

1. choose both Canadian and U.S. discount rates for both generating and transmission technologies, to permit the investigation of public and private sector financing options;
2. modifications of demand growth rates by region, in order to investigate demand-side management and conservation options;
3. modification of supply cost factors, to incorporate environmental costs;
4. impact of new technological developments, particularly in the area of long-distance transmission;
5. restrictions on the development of certain supply technologies (i.e., no new nuclear plants in the U.S. to the end of the century; restrictions on mix of nuclear-coal in Ontario); and
6. policy restrictions on interregional transfer of power, particularly exports.

E.3 Model Inputs

The following data are required:

1. forecasts for peak and energy power demand in each region over time;
2. forecasts of resource prices in each region over time--coal, natural gas, fuel oil, enriched uranium fuel;
3. capital and operating costs for all power generating technologies being considered;

4. operating characteristics of all power generating technologies being considered; and
5. all policy or financial constraints to be explicitly stated in quantitative terms.

E.4 Model Variables

The model solves for the following set of decision variables:

1. the optimal generating capacity expansion expansion schedule in each region over time, by technology;
2. the optimal construction schedule for new interregional transmission lines;
3. the load mix in each region over time by technology; and
4. interregional transfers of power.

From these variables, a number of accounting variables can be calculated, including capital cost requirements by year and by region, fuel resource usage by year and by region, and volume of effluent discharges by year and by region.

The net savings as a result of power transfer from one region to another region are explicitly calculated. These savings represent the difference between the avoided cost in the importing region and the delivered cost from the exporting region (supply cost plus transmission cost).

E.5 Scenario Results

The cases presented in Section 5.5, Volume I are presented in detail here. Additional information on the ELGEM model and regional data used to estimate these results is available by writing the Oil Sands Research Department, Alberta Research Council, 1021 Hayter Road, Edmonton, Alberta, Canada, T6H 5X2.

The Coal and Electricity Division of the Canadian Energy Research Institute is presently updating the ELGEM model so as to analyze the future emissions of SO_2, NO_x and CO_2 and the impact on emission levels of new coal and nuclear power technologies and investment in conservation and demand-side management.

Footnotes

[1] J. S. Rogers and S. K. Choudhury, "Planning Inter-Regional Electric Energy Supply in Canada (1980-2010): A Linear Programming Approach," proceedings of the Sixth Power Systems Computation Conference, Darmstadt, West Germany, 1978, pp. 22-29.

[2] Energy, Mines and Resources Canada, UEXGEN MODEL USER's GUIDE (Ottawa: The Financial & Market Analysis Branch, Market Analysis Section, Energy, Mines and Resources Canada, December 1985).

CASE 1 - NO NEW TRADE

(A) Run Parameters

Planning Period	1987-2010
No. of Time Periods	8
Length of Time Period, years	3
Overall Discount Rate, % annum	5
Demand Scenarios	
Canada	Medium
U.S.A.	Medium
Supply Scenarios	
Canadian Costs	Standard
Data Source for Cdn. Hydro Costs	United States Department of Energy. Northern Lights: The Economic and Practical Potential of Imported Power from Canada. By Jeffrey Skeer. Washington, D.C.: U.S. Department of Energy, December 1987.
Cost of Capital, % ann.	
Generating	
Canada	5
U.S.A.	5
Transmission (both Can. and U.S.)	5
Ontario Nuclear/Coal Mix (new)	0.5

(B) Overall Results

Objective Function (billions $1988 Cdn.)	($1,619)

NPV Construction at 5% real	(billions $1988 Cdn.)
B.C.	$2.74
Alta.	$4.85
Sask.	$0.44
Man.	$0.90
Ont.	$0.00
Que.	$19.95
Atl.	$1.92
Nfld.	$0.49
Canada Total	$31.28

NPV Trade Savings	(millions of $1988 Cdn.)
Canadian Interties	
Man. - Ont.	0.0
Que. - Ont.	0.0
Nfld. - Que.	0.0
Canadian Export Links	
B.C. - California (Cal.)	0.0
Alta. - Cal.	0.0
Man. - US North Central (USNC)	0.0
Ont. - USNC	0.0
Que. - US North East (USNE)	0.0
Que. - USNE	0.0
Atl. - USNE	0.0
Nfld. - USNE	0.0

(C) Regional Results

Canadian Generating Capacity Added (GW)

Year	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.
1988	0.0	0.0	0.0	2.4	0.0	1.7	0.0	1.4
1991	0.0	0.4	0.0	0.0	0.0	0.0	0.1	0.0
1994	0.0	0.9	0.2	0.0	0.0	3.0	0.1	0.0
1997	0.4	1.1	0.2	0.0	0.0	3.6	0.5	0.0
2000	0.4	1.2	0.2	0.0	0.0	5.8	0.5	4.6
2003	0.5	0.7	0.2	0.2	0.0	1.9	0.4	0.0
2006	1.0	1.2	0.3	0.3	0.0	2.6	0.6	0.1
2009	1.6	1.7	0.3	0.4	0.0	3.0	0.8	0.2

Canadian Investment in Generating Capacity
(millions of $1988 Cdn.)

Year	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.
1988	0	666	0	0	0	2154	34	0
1991	0	814	69	0	0	4719	34	37
1994	137	805	69	78	0	4791	236	37
1997	463	893	69	195	0	4665	585	120
2000	1102	1054	73	377	0	3165	881	110
2003	1073	914	190	312	0	2567	510	157
2006	806	760	85	208	0	1747	137	167
2009	0	0	0	0	0	0	0	0

(D) Regional Trade

Canadian

Regional Pairings
(GW)

Year	Man.-Ont.	Que.-Ont.	Nfld.-Que.
1988	0.0	0.0	0.0
1991	0.0	0.0	0.0
1994	0.0	0.0	0.0
1997	0.0	0.0	0.0
2000	0.0	0.0	0.0
2003	0.0	0.0	0.0
2006	0.0	0.0	0.0
2009	0.0	0.0	0.0

Export

Regional Pairings

Year	B.C.-Cal.	Alta.-Cal.	Man.-USNC	Ont.-USNC	Que.-USNC	Que.-USNE	Atl.-USNE	Nfld.-USNE
1988	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0

(E) Trade Savings

Canadian

Regional Pairings
(millions of $1988 Cdn.)

Year	Man.-Ont.	Que.-Ont.	Nfld.-Que.
1988	0.0	0.0	0.0
1991	0.0	0.0	0.0
1994	0.0	0.0	0.0
1997	0.0	0.0	0.0
2000	0.0	0.0	0.0
2003	0.0	0.0	0.0
2006	0.0	0.0	0.0
2009	0.0	0.0	0.0

Export

Regional Pairings

Year	B.C.-Cal.	Alta.-Cal.	Man.-USNC	Ont.-USNC	Que.-USNC	Que.-USNE	Atl.-USNE	Nfld.-USNE
1988	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0

CASE 2 - FULL TRADE

(A) Run Parameters

Planning Period	1987-2010
No. of Time Periods	8
Length of Time Period, years	3
Overall Discount Rate, % annum	5
Demand Scenarios	
Canada	Medium
U.S.A.	Medium
Supply Scenarios	
Canadian Costs	Standard
Data Source for Cdn. Hydro Costs	United States Department of Energy. *Northern Lights: The Economic and Practical Potential of Imported Power from Canada*. By Jeffrey Skeer. Washington, D.C.: U.S. Department of Energy, December 1987.
Cost of Capital, % ann.	
Generating	
Canada	5
U.S.A.	5
Transmission (both Can. and U.S.)	5
Ontario Nuclear/Coal Mix (new)	0.5

(B) Overall Results

Objective Function (billions $1988 Cdn.)	($1,593)

NPV Construction at 5% real	(billions $1988 Cdn.)
B.C.	$18.45
Alta.	$8.63
Sask.	$0.44
Man.	$4.62
Ont.	$12.03
Que.	$34.59
Atl.	$3.33
Nfld.	$3.15
Canada Total	$85.24

NPV Trade Savings	(millions of $1988 Cdn.)
Canadian Interties	
Man. - Ont.	22.9
Que. - Ont.	106.9
Nfld. - Que.	0.1
Canadian Export Links	
B.C. - Cal.	1374.7
Alta. - Cal.	637.9
Man. - USNC	253.6
Ont. - USNC	617.8
Que. - USNE	4.8
Que. - USNE	261.7
Atl. - USNE	31.5
Nfld. - USNE	173.2

(C) Regional Results

Canadian Generating Capacity Added (GW)

Year	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.
1988	0.0	0.2	0.0	2.4	0.0	3.2	0.0	0.5
1991	0.0	1.2	0.0	0.0	0.0	0.0	0.1	0.0
1994	1.9	1.2	0.2	0.0	0.0	3.6	0.1	0.0
1997	1.9	2.2	0.2	0.0	0.0	5.1	0.5	0.5
2000	2.2	1.4	0.2	0.0	2.2	5.5	0.4	0.8
2003	2.6	1.7	0.2	3.2	2.6	7.4	0.4	1.0
2006	3.1	1.7	0.3	0.5	2.6	4.7	1.6	0.3
2009	3.6	1.8	0.3	0.3	2.6	3.2	0.8	0.0

Canadian Investment in Generating Capacity
(millions of $1988 Cdn.)

Year	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.
1988	1876	1052	0	0	176	3265	56	184
1991	3236	1052	69	0	1063	6317	222	478
1994	3489	1750	69	1248	2989	8547	786	1005
1997	3959	1830	69	1545	3549	8613	1140	1071
2000	4415	2269	73	2140	3806	8072	1003	777
2003	3487	1599	190	575	2594	4576	771	250
2006	1965	963	85	238	668	2165	137	0
2009	0	0	0	0	0	0	0	0

(D) Regional Trade

Canadian

Regional Pairings
(GW)

Year	Man.-Ont.	Que.-Ont.	Nfld.-Que.
1988	0.3	0.0	0.0
1991	0.3	0.0	0.0
1994	0.1	2.2	0.0
1997	0.3	2.1	0.0
2000	0.0	1.7	0.0
2003	0.3	0.2	0.0
2006	0.3	0.0	0.2
2009	0.0	0.0	0.0

Export

Regional Pairings

Year	B.C.-Cal.	Alta.-Cal.	Man.-USNC	Ont.-USNC	Que.-USNC	Que.-USNE	Atl.-USNE	Nfld.-USNE
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	0.4	1.6	0.0	0.0	0.0	0.0	0.0	0.0
2000	3.4	1.7	0.0	0.0	0.0	0.0	0.0	0.0
2003	4.5	2.3	1.9	0.0	1.3	3.5	0.0	1.5
2006	5.6	2.7	2.1	9.9	0.4	4.8	0.7	1.8
2009	6.8	2.7	2.3	12.0	5.2	0.0	0.7	1.5

(E) Trade Savings

Canadian

Regional Pairings
(millions of $1988 Cdn.)

Year	MN-ON	QU-ON	NF-QU
1988	5.17	0.00	0.00
1991	5.17	0.00	0.00
1994	1.72	46.02	0.00
1997	5.17	43.93	0.00
2000	0.00	35.56	0.00
2003	5.17	4.18	0.00
2006	5.17	0.00	0.10
2009	0.00	0.00	0.00

Export

Regional Pairings

Year	B.C.- Cal.	Alta.- Cal.	Man.- USNC	Ont.- USNC	Que.- USNC	Que.- USNE	Atl.- USNE	Nfld.- USNE
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	25.6	88.7	0.0	0.0	0.0	0.0	0.0	0.0
2000	262.6	116.7	0.0	0.0	0.0	0.0	0.0	0.0
2003	383.6	176.3	95.1	0.0	69.9	146.2	0.0	66.6
2006	530.0	232.3	118.2	366.1	24.0	214.8	17.7	85.2
2009	716.5	261.3	145.7	528.4	348.6	0.0	27.9	93.0

CASE 3 - NO NEW EXPORTS

(A) Run Parameters

Planning Period	1987-2010
No. of Time Periods	8
Length of Time Period, years	3
Overall Discount Rate, % annum	5
Demand Scenarios	
Canada	Medium
U.S.A.	Medium
Supply Scenarios	
Canadian Costs	Standard
Data Source for Cdn. Hydro Costs	United States Department of Energy. Northern Lights: The Economic and Practical Potential of Imported Power from Canada. By Jeffrey Skeer. Washington, D.C.: U.S. Department of Energy, December 1987.
Cost of Capital, % ann.	
Generating	
Canada	5
U.S.A.	5
Transmission (both Can. and U.S.)	5
Ontario Nuclear/Coal Mix (new)	0.5

(B) Overall Results

Objective Function (billions $1988 Cdn.)	($1,616)

NPV Construction at 5% real	(billions $1988 Cdn.)
B.C.	$2.74
Alta.	$4.85
Sask.	$0.44
Man.	$0.90
Ont.	$0.00
Que.	$27.11
Atl.	$1.92
Nfld.	$0.49
Can. Total	$38.44

NPV Trade Savings	(millions of $1988 Cdn.)
Canadian Interties	
Man. - Ont.	30.4
Que. - Ont.	259.1
Nfld. - Que.	0.0
Canadian Export Links	
B.C. - Cal.	0.0
Alta. - Cal.	0.0
Man. - USNC	0.0
Ont. - USNC	0.0
Que. - USNE	0.0
Que. - USNE	0.0
Atl. - USNE	0.0
Nfld. - USNE	0.0

(C) Regional Results

Canadian Generating Capacity Added
(GW)

Year	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.
1988	0.0	0.0	0.0	2.4	0.0	3.3	0.0	0.5
1991	0.0	0.4	0.0	0.0	0.0	0.0	0.1	0.0
1994	0.0	0.9	0.2	0.0	0.0	3.6	0.1	0.0
1997	0.4	1.1	0.2	0.0	0.0	5.0	0.5	0.0
2000	0.4	1.2	0.2	0.0	0.0	4.6	0.5	2.8
2003	0.5	0.7	0.2	0.2	0.0	3.4	0.4	0.0
2006	1.0	1.2	0.3	0.3	0.0	4.9	0.6	0.1
2009	1.6	1.7	0.3	0.4	0.0	3.5	0.8	0.2

Canadian Investment in Generating Capacity (millions of $1988 Cdn.)

Year	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.
1988	0	666	0	0	0	3191	34	0
1991	0	814	69	0	0	5347	34	37
1994	137	805	69	78	0	5611	236	37
1997	463	893	69	195	0	5866	585	120
2000	1102	1054	73	377	0	5713	881	110
2003	1073	914	190	312	0	4644	510	157
2006	806	760	85	208	0	2262	137	167
2009	0	0	0	0	0	0	0	0

(D) Regional Trade

Canadian

Regional Pairings (GW)

Year	Man.-Ont.	Que.-Ont.	Nfld.-Que.
1988	0.3	0.0	0.0
1991	0.3	1.2	0.0
1994	0.1	2.2	0.0
1997	0.3	2.1	0.0
2000	0.3	1.5	0.0
2003	0.3	2.2	0.0
2006	0.3	3.4	0.2
2009	0.3	3.6	0.0

Export

Regional Pairings

Year	B.C.-Cal.	Alta.-Cal.	Man.-USNC	Ont.-USNC	Que.-USNC	Que.-USNE	Atl.-USNE	Nfld.-USNE
1988	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0

(E) Trade Savings

Canadian

Regional Pairings
(millions of $1988 Cdn.)

Year	Man.-Ont.	Que.-Ont.	Nfld.-Que.
1988	5.17	0.00	0.00
1991	5.17	25.10	0.00
1994	1.72	46.02	0.00
1997	5.17	43.93	0.00
2000	5.17	31.38	0.00
2003	5.17	46.02	0.00
2006	5.17	71.12	0.00
2009	5.17	75.30	0.00

Export

Regional Pairings

Year	B.C.-Cal.	Alta.-Cal.	Man.-USNC	Ont.-USNC	Que.-USNC	Que.-USNE	Atl.-USNE	Nfld.-USNE
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

CASE 4 - FULL TRADE
(ONTARIO - NUCLEAR)

(A) Run Parameters

Planning Period	1987-2010
No. of Time Periods	8
Length of Time Period, years	3
Overall Discount Rate, % annum	5
Demand Scenarios	
Canada	Medium
U.S.A.	Medium
Supply Scenarios	
Canadian Costs	Standard
Data Source for Cdn. Hydro Costs	United States Department of Energy. Northern Lights: The Economic and Practical Potential of Imported Power from Canada. By Jeffrey Skeer. Washington, D.C.: U.S. Department of Energy, December 1987.
Cost of Capital, % ann.	
Generating	
Canada	5
U.S.A.	5
Transmission (both Can. and U.S.)	5
Ontario Nuclear/Coal Mix (new)	0.99

(B) Overall Results

Objective Function (billions $1988 Cdn.)	($1,[illegible]93)

NPV Construction at 5% real	(billions $1988 Cdn.)
B.C.	$18.45
Alta.	$8.63
Sask.	$0.44
Man.	$4.62
Ont.	$12.21
Que.	$34.08
Atl.	$3.53
Nfld.	$3.15
Canada Total	$85.12

NPV Trade Savings	(millions of $1988 Cdn.)
Canadian Interties	
Man. - Ont.	24.4
Que. - Ont.	59.8
Nfld. - Que.	0.1
Canadian Export Links	
B.C. - Cal.	1374.7
Alta. - Cal.	637.9
Man. - USNC	253.6
Ont. - USNC	634.9
Que. - USNE	4.2
Que. - USNE	249.0
Atl. - USNE	31.5
Nfld. - USNE	173.2

(C) Regional Results

Canadian Generating Capacity Added
(GW)

Year	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.
1988	0.0	0.2	0.0	2.4	0.0	3.2	0.0	0.5
1991	0.0	1.2	0.0	0.0	0.0	0.0	0.1	0.0
1994	1.9	1.2	0.2	0.0	0.2	3.2	0.1	0.0
1997	1.9	2.2	0.2	0.0	1.2	3.6	0.5	0.5
2000	2.2	1.4	0.2	0.0	1.2	5.3	0.5	0.8
2003	2.6	1.7	0.2	3.2	1.6	7.4	0.6	1.0
2006	3.1	1.7	0.3	0.5	2.7	6.4	1.5	0.3
2009	3.6	1.8	0.3	0.3	2.7	3.8	0.8	0.0

Canadian Investment in Generating Capacity (millions of $1988 Cdn.)

Year	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Nfld.
1988	1876	1052	0	0	1224	2043	34	184
1991	3236	1052	69	0	1811	5431	163	478
1994	3489	1750	69	1248	2187	7732	914	1005
1997	3959	1830	69	1545	2559	9145	1356	1071
2000	4415	2269	73	2140	3766	8943	1017	777
2003	3487	1599	190	575	2656	5651	737	250
2006	1965	963	85	238	673	2511	137	0
2009	0	0	0	0	0	0	0	0

(D) Regional Trade

Canadian

Regional Pairings (GW)

Year	Man.-Ont.	Que.-Ont.	Nfld.-Que.
1988	0.3	0.0	0.0
1991	0.3	0.0	0.0
1994	0.2	2.0	0.0
1997	0.3	0.9	0.0
2000	0.0	0.5	0.0
2003	0.3	0.0	0.1
2006	0.3	0.0	0.2
2009	0.0	0.0	0.0

Export

Regional Pairings

Year	B.C.-Cal.	Alta.-Cal.	Man.-USNC	Ont.-USNC	Que.-USNE	Que.-USNE	Atl.-USNE	Nfld.-USNE
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	0.4	1.6	0.0	0.0	0.0	0.0	0.0	0.0
2000	3.4	1.7	0.0	0.0	0.0	0.0	0.0	1.5
2003	4.5	2.3	1.9	1.2	0.1	3.5	0.0	1.8
2006	5.6	2.7	2.1	9.5	0.8	4.4	0.7	1.5
2009	6.8	2.7	2.3	12.0	5.2	0.0	0.7	1.5

(E) Trade Savings

Canadian

Regional Pairings
(millions of $1988 Cdn.)

Year	Man.-Ont.	Que.-Ont.	Nfld.-Que.
1988	5.17	0.00	0.00
1991	5.17	0.00	0.00
1994	3.44	41.83	0.00
1997	5.17	18.83	0.00
2000	0.00	10.46	0.00
2003	5.17	0.00	0.05
2006	5.17	0.00	0.10
2009	0.00	0.00	0.00

Export

Regional Pairings

Year	B.C.-Cal.	Alta.-Cal.	Man.-USNC	Ont.-USNC	Que.-USNC	Que.-USNE	Atl.-USNE	Nfld.-USNE
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	25.6	88.7	0.0	0.0	0.0	0.0	0.0	0.0
2000	262.6	116.7	0.0	0.0	0.0	0.0	0.0	0.0
2003	383.6	176.3	95.1	36.9	5.4	146.2	0.0	66.6
2006	530.0	232.3	118.2	351.3	48.0	196.90	17.70	85.2
2009	716.5	261.3	145.7	528.4	348.6	0.0	27.9	93.0

APPENDIX F

GLOSSARY

Appendix F

GLOSSARY

These definitions are taken from the House of Commons report, Nuclear Energy: Unmasking the Mystery, August 1988; World Resources Institute and International Institute for Environmental and Development, World Resources 1988-89; Energy, Mines and Resources Canada, Electric Power in Canada 1988; House of Commons report, Report of the Special Committee on Acid Rain; and U.S. Congress, Office of Technology Assessment, Electric Power: Wheeling and Dealing.

ACID: A concentration of hydrogen ions (H+) in solution. Acidity is expressed on a numerical pH scale. An acidic solution has a pH less than 7.0.

ACID RAIN: A general term describing precipitation in any form that has been acidified by the presence of atmospheric pollutants, primarily the oxides of sulphur and nitrogen.

ACID RAIN PRECURSOR: A material such as SO_2 or NO_x which is transformed in the atmosphere to become a component of acid rain.

AEROSOL: A suspension of liquid or solid particles in a gas.

ALKALINITY: A measure of water's ability to neutralize added acids by the reaction of hydrogen ions with carbonate, bicarbonate, and hydroxide ions.

ALTERNATING CURRENT: An electric current that flows alternately in one direction and then in the reverse direction. In North America, the standard for alternating current is 60 complete cycles per second; such electricity is said to have a frequency of 60 hertz. Alternating current is used in almost all aspects of power systems because it can be transmitted and distributed much more economically than direct current.

ALTERNATIVE ENERGY/TECHNOLOGY: Energy sources or technologies which are not yet widely used, as opposed to "conventional" energy/technology. The term usually refers to renewable energy sources and small, decentralized installations. Examples are photovoltaics, solar heating, wind power and waste-fuelled electrical generation.

ARTIFICIALLY-FIXED NITROGEN: Traditional farmers intervene in the nitrogen cycle by cultivating legumes interspersed with other crops, or in rotation with them, plowing legumes under as green manure and by recycling biomass such as crop residues and animal and human wastes. Modern agriculture retains some of these practices, but the total mass of recycled organic nitrogen is now dwarfed by industrial production of nitrogen fertilizers from atmospheric nitrogen. Synthetic ammonia production has grown exponentially since its commercialization in the early 1920s. Worldwide output is now 90 million metric tons of nitrogen, with 80 percent used as fertilizer.

Synthetic ammonia is used directly as a cheap, highly concentrated fertilizer or converted to urea, nitrates, or compound fertilizers (combinations of nitrogen with phosphate, potassium, and micronutrient elements).

When excess nitrogen fertilizer is applied to a field the levels of nitrate in the runoff and nitrous oxide in the atmosphere increase. Nitrous oxide levels are enhanced because nitrification and denitrification, which convert nitrogen fertilizers and biomass to nitrous oxide and then to nitrogen gas, sometimes stops with the production of nitrous oxide. When farmers fertilize or over-fertilize crops with synthetic nitrogen fertilizers produced from nitrogen gas, they essentially withdraw nitrogen from the atmosphere in its stable molecular form and return some of it as nitrous oxide, a compound that has important environmental impacts.

ASSURED SYSTEM CAPACITY: The dependable power-generating capacity of system facilities available for serving system load after making provision for required reserve generation, including the effects of agreements with other systems.

ASYNCHRONOUS TIE: A direct-current interconnection between two alternating-current systems, so-called because the two systems need not be in synchronism with each other.

AVERAGE ENERGY: The energy which would be generated by the hydroelectric stations in a river system under average streamflow conditions.

AVERAGE STREAMFLOW: The arithmetic average of all recorded flows in a river over a specified period of time, usually measured on an annual basis.

AVOIDED COST: The cost which would be incurred by an electric utility in providing new generating capacity if the utility were to provide the power itself instead of purchasing it from an independent generator.

BASE: The opposite of acid; depends on the concentration of hydroxyl ions (OH-) in solution. A basic alkaline solution has a pH greater than 7.0.

BASE LOAD: The minimum continuous load over a given period of time.

BASE-LOAD GENERATING STATION: A generating station which is normally operated to supply all or part of the base load of a system and which consequently operates at full output whenever available. Base-load generating units tend to be large units with low operating costs.

BUFFER: A chemical which, in solution, will resist changes in pH or, if added to a solution, will change the pH of that solution. In nature, limestone (calcium carbonate) will act as a buffer against acid rain to maintain or raise the pH of a waterbody.

BULK ELECTRICITY SYSTEM: The generation and high voltage transmission facilities (generally 115 kilovolts and up) considered as a whole.

BUS: A set of electrical conductors that serves as a common connection for two or more circuits. A bus may be in the form of rigid bars ("busbars") or in the form of cables.

CARBON DIOXIDE: Emissions caused by natural and human factors. Volcanoes emit carbon dioxide, and major changes in global vegetation can contribute to, or withdraw from, the atmospheric carbon reservoir. Combustion of fossil fuels adds carbon to the atmosphere, as do gas flaring and cement production. In addition, carbon is released by the burning or decomposition of the biomass when forestland is cleared.

CAPABILITY: The maximum load that a station or equipment is capable of carrying under specified conditions.

CAPACITY: The rate of delivery of energy (for example, a utility might sell 50 megawatts of capacity or electric power) or the maximum quantity of power that a piece of equipment or a system is capable of carrying or supplying (for example, a generating unit might have a rated capacity of 50 megawatts).

CAPACITY FACTOR: For any equipment, the ratio of the average load during some period of time to the rated capacity of the equipment. Capacity is usually expressed as a percentage.

CHLOROFLUOROCARBONS: Chlorofluorocarbons (CFCs), in the form of CFC-11, CFC-12, and CFC-113, affect the climate through their absorption of infrared radiation and their reaction in the atmosphere with other chemicals. The CFCs produce a highly reactive form of chlorine, which in turn depletes the stratospheric ozone layer. In Canada, almost 70 percent of CFCs are used in air conditioning, and rigid foam insulation.

On July 1, 1989, Environment Canada introduced regulations that will reduce the use of CFCs in Canada to 50 percent of their 1986 levels by 1999. In light of recent information regarding the impact of CFCs on the ozone layer, further reductions may be required. In February 1989, Ontario announced that its Environmental Protection Act will be amended to eliminate the manufacture and use of CFCs.

CIRCUIT: Any conductor or set of conductors intended to carry electricity.

CIRCUIT BREAKER: A switching device to open or close an electric power circuit during either normal system operation or fault conditions.

COGENERATION: The combined production of electricity and useful heat (usually steam).

CONSUMPTION: Use of electrical energy, typically measured in kilowatt-hours.

CONTROL CENTRE: The control room from which instructions are issued for switching of power system equipment, stations or lines, and for changing the amount of power generated in power stations. Typically such a centre is equipped with remote controls, telemetering and computer facilities. Automated system maps indicate the operating status of generating units, transmission lines and main substation equipment. Metering devices show the loads being carried by units and lines, and the voltage levels at selected locations. Thus the system supervisor is provided with a complete picture of the main features of the power system and can coordinate its operations.

CONVENTIONAL GENERATION: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

CONVERTER STATION: An installation for converting direct current into alternating current, or for changing one frequency of alternating current to another.

CURRENT: The flow of electricity in a conductor. Current is measured in amperes.

DEMAND: The desire of purchasers for electricity. "Demand" is often used synonymously with "power" which is the rate at which electrical energy is being delivered.

DEMAND CHARGE: The component of a two-part price for electricity which is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used. The other component of the two-part price is the energy charge.

DEMAND MANAGEMENT: Actions taken by a utility or other agency intended to influence the amount or timing of customers' use of electricity.

DEPENDABLE CAPACITY: The load-carrying ability of a station or system under adverse conditions, as for example, the capacity of a hydroelectric station under defined low-flow conditions.

DIRECT CURRENT: Current that flows continuously in one direction (as opposed to an alternating current). The current supplied from a battery is direct current.

DIRECT CURRENT TRANSMISSION: Transmission of electricity by direct current instead of the usual alternating current. Direct current has certain advantages for long-distance, point-to-point transmission and for interconnecting power systems that would otherwise be unstable if an attempt were made to tie them together by alternating current transmission. There are four high-voltage dc installations in service in Canada: (1) the Vancouver Island underwater transmission link; (2) the Nelson River (Manitoba) overhead transmission line; (3) the Eel River (New Brunswick) asynchronous tie; and (4) the Chateauguay (Quebec) asynchronous tie.

DISTRIBUTION SYSTEM: The lines, transformers, switches, etc. used to distribute electricity over short distances from the transmission system to customers. Distribution generally takes place at relatively low voltages (44 kilovolts and less).

DRY DEPOSITION: A process whereby particles such as fly ash, sulphates and nitrates, and gases such as sulphur dioxide and nitric oxide are deposited on, or absorbed onto, surfaces. The dry particles or gases can be converted into acids after deposition when they contact water.

ECONOMIC DISPATCH: A system for selecting generating units to operate to balance supply and demand at minimum cost.

ECONOMY ENERGY: Energy sold by one power system to another to effect a saving in the cost of generation when the receiving utility has adequate capability to supply the loads on its own system.

ELECTRICAL POWER: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

ELECTRICAL UTILITY: An organization that has as its prime purpose the generation, transmission and/or distribution of electric energy for sale.

ELECTRO-TECHNOLOGY: A technology that uses electricity in its processes, especially new technologies used to displace other energy sources. An example is the use of electrically-driven heat pumps for kiln drying wood, in place of air heated by on-site fuel combustion.

ENERGY CHARGE: The component of a two-part price for electricity that is based on the amount of energy taken. The other component of price is the demand charge.

ENERGY SOURCE: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

EXTRA HIGH VOLTAGE (EHV): Any transmission voltage higher than those commonly used. The utility industry has generally considered EHV to be 345 kilovolts (kV) or higher, although such voltages are becoming increasingly common.

FIRM ENERGY OR POWER: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

FLUIDIZED-BED COMBUSTION: A method of combustion in which air, blown up through orifices in the floor of the firebox, suspends particles as a fluidized bed. The particles consist of fuel and a sorbent such as limestone.

FORCED OUTAGE RATE: The probability that a particular generating unit or other system component will be unavailable for service because of breakdown.

FREQUENCY: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

FUEL REPLACEMENT ENERGY: Energy sold by one utility to another to enable the purchaser to avoid burning fuel in its own thermal generating facilities. Fuel replacement energy is typically priced at a percentage of the fuel cost avoided by the purchasing utility.

GENERATING STATION: A station comprising one or more generating units for the production of electricity. The main types of generating stations are hydroelectric, nuclear-electric and fossil-fuelled (by coal, oil or natural gas). In some parts of the world, such as the Geysers region of California, geothermal-electric power is becoming an important element of generating capacity.

GENERATING UNIT: An electric generator, the prime mover that drives the generator, and all the associated equipment that must be operated together as a group to generate electricity.

A generating unit can usually operate independently of other units at a multi-unit station.

GENERATION REJECTION: Disconnecting selected generating units from a power system to preserve the continuing safe operating of the rest of the system. This action is sometimes taken if a large block of load has suddenly been cut off by some emergency, leaving generators feeding into the system without enough connected load to absorb their output. The units would otherwise overspeed, raising the frequency and voltage on the system to unacceptable levels.

GIGAWATT (GW): One billion watts. (See Watt.)

GIGAWATT HOUR (GW.h): A unit of bulk energy. A million kilowatt-hours. A billion watt hours.

GRID: A network of electric power lines and connections.

GROSS DOMESTIC PRODUCT (GDP): The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

GROSS NATIONAL PRODUCT (DNP): The total value of production of goods and services measured at market prices.

HEAD (HYDRAULIC): The difference in elevation between the water level immediately above a hydroelectric generating station and the water level immediately below it. The power output of the station is proportional to the hydraulic head.

HEAT RATE: A measure of generating station thermal efficiency, generally expressed as British thermal units per net kilowatt-hour. It is computed by dividing the total heat (Btu) content of the fuel burned by the resulting net kilowatt-hours of electricity generated. In metric units, the heat rate is expressed as kilojoules per kilowatt-hour.

HERTZ (HZ): The units of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 hertz.

HIGH TENSION: Any voltage in excess of 750 volts.

HYDROELECTRIC STATION: An electric generating station in which the prime movers are hydraulic turbines.

INCREMENTAL GENERATING COST: The cost of generating one additional unit of electric energy above some previously determined base quantity.

INDEPENDENT (PRIVATE) GENERATION: Generation owned or operated by producers other than a utility. These producers usually have generating plants for the purpose of supplying electric power required in their own industrial and commercial operations. The term also covers private plants whose sole purpose is the sale of electricity to a utility.

INSTALLED (GENERATING) CAPACITY: The capacity measured at the output terminals of all the generating units in a station, before deduction of station service requirements.

INTEGRATED PLANNING: Joint planning by different power systems in order to minimize total costs. Integrated planning is one characteristic of a true power pool.

INTERCONNECTION AGREEMENT: An agreement made between two power utilities to govern the operation of interconnections between their systems. Typically such an agreement defines different classes of inter-utility electricity transfers and specifies how they shall be priced between the two companies.

INTERCONNECTED SYSTEM: A system consisting of two or more individual power systems connected together by tie lines.

INTERRUPTIBLE ENERGY OR POWER: Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

INTER-UTILITY TRANSFER: A transfer of electric power between two or more electrical utilities. The NEB Part VI Regulations define five classes of inter-utility transfer. These are:

(1) Adjustment transfer: A transfer of electric power or energy made: (a) to adjust an energy account balance; (b) to compensate for electrical losses; (c) to compensate for services rendered; (d) to deliver output entitlements; or (e) to provide upstream or downstream benefits.

(2) Carrier transfer: A transfer of electric power or energy by one utility over the circuits of another, for delivery either to a third party or back to the originating utility.

(3) Equichange transfer: An interchange of equal quantities of electric power or energy within a stated period.

(4) Sale transfer: A transfer of electric power or energy under a contract of sale.

(5) Storage transfer: An electric energy transfer "banked" for the time being in the form of water in the reservoir space of another electrical utility, in the expectation that equivalent electric energy will be returned at a later time.

ISOLATED SYSTEM: An electric power system not interconnected with any other system (such as the Northern Canada Power Commission). Isolated systems are usually of relatively small capacity.

JOULE: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt-hour.

KILOVOLT (kV): 1000 volts.

KILOWATT (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

KILOWATT-HOUR (kW.h): The commercial unit of electric energy; 1000 watt hours. A kilowatt-hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt-hour is equal to 3.6 million joules.

LEACHING: A natural process by which water dissolves minerals out of rocks. The leaching of heavy metals, such as mercury, into water supplies is believed to be a serious consequence of acid rain.

LICENCE: A licence to export electricity from Canada, issued under Part VI of the National Energy Board Act, following a public hearing. A licence is subject to the approval of the Governor in Council.

LIMESTONE: A sedimentary rock consisting chiefly of calcium carbonate. Limestone is an effective buffer against acid rain.

LOAD: The amount of electric power or energy consumed by a particular customer or group of customers.

LOAD CURVE (SHAPE): The pattern of electricity use or production when demand is plotted against time.

LOAD FACTOR: The ratio of the average load during a designated period to the peak or maximum load in that same period, usually expressed as a percentage of the peak load.

LOAD MANAGEMENT: The manipulation of customer demand by economic and/or technical means.

LOAD REJECTION (LOAD SHEDDING): Interrupting the supply of electricity to a selected region or group of customers as a means of preserving the continuing safe operation of the remainder of a power system. This action is sometimes taken in an emergency when the total system load exceeds the capacity of the generation available to supply it.

LOAD SHIFTING: Shifting electrical demand from one period to another, usually from high-load to low-load periods.

LOCKED-IN ENERGY: Energy production capability at a generating station which cannot be used because of inadequate transmission capability connecting the generating station to the load. For example, part of the generating capacity of the Bruce Nuclear Generating Station is locked in.

LOOP FLOWS: Parallel path flows crossing utilities' boundaries along paths not contracted for or scheduled.

LOSSES: Energy or power lost in circuits or equipment, mainly in the form of heat, when current flows through the circuit.

MARGINAL COST: The cost of supplying an additional unit of output. When the extra unit of output can be supplied simply by increasing production from the existing plant, it is usually specified at the "short-run marginal cost" or "incremental cost;" when new plant is required to supply the additional production, it is usually termed the "long-run marginal cost."

MARGINAL COST PRICING: A rate structure in which prices are set at the cost of the last (marginal) unit of production, rather than at cost of production averaged over all output.

MEGAWATT (MW): a unit of bulk power; 1000 kilowatts.

MEGAWATT HOUR (MW.h): A unit of bulk energy; 1000 kilowatt-hours.

METHANE (CH_4): After carbon dioxide, methane is the second largest contributor to the greenhouse effect. Most methane emissions are generated by natural sources such as decomposition of materials in wetlands and by non-energy-related human activities such as agriculture and animal husbandry. The production and use of energy account for only a limited share of methane emissions.

MILL: 1/1000 of a dollar.

MOTHBALL: To take equipment that is surplus to current needs or that has reached the end of its normal life and retain it in a preserved state. Mothballed equipment is not available for immediate use but can, with preparation, be resurrected for future use.

NAME-PLATE RATING: The full-load continuous rating of a generator or other electrical equipment under the conditions designated by the manufacturer, as indicated on the name plate attached to the device.

NATIONAL AMBIENT AIR QUALITY OBJECTIVES: Prescribed by the federal government under the *Canadian Environmental Protection Act* to reflect regional air quality goals in three ranges–"tolerable," "acceptable," and "desirable." They are not source-specific but are geographical area-specific. They are applicable to specific air contaminants. They are enforceable by the provinces once adopted by them as part of their environmental laws in virtue of a federal-provincial agreement under the federal *Canadian Environmental Protection Act*.

NITROUS OXIDE (N_2O): Combustion of fossil fuels releases nitrous oxide, which affects the formation of ozone in the troposphere. Data are not available on levels of nitrous oxide emissions from the combustion of different fossil fuels. The non-energy sources of nitrous oxide emissions such as the use of agricultural fertilizers are believed to be far larger than the energy-related sources. About one-third of total global N_2O emissions are anthropogenic, resulting mainly from fertilizer application and to a lesser extent from large stationary combustion sources. Mobile sources are not significant emittors of N_2O.

NONFERROUS SMELTING: The smelting, roasting, and sintering of sulphur-containing ores, such as those containing copper or nickel, and scrap materials.

NUCLEAR FUEL: A substance containing one or more fissile nuclides capable of maintaining a chain reaction in a reactor. The term may also be used to include a substance containing one or more fertile nuclides that can be transmuted into such fissile nuclides.

NUCLEAR POWER: Power generated at a station where the steam to drive the turbines is produced by the process of atomic fission, rather than by burning a combustible fuel.

NUCLEAR (FISSION) REACTOR: A device in which a self-sustaining nuclear fission chain reaction can be maintained and controlled. The term "nuclear reactor" is sometimes applied to a device in which a nuclear fusion reaction can be produced and controlled (fusion reactor).

NUCLIDE: An individual atomic species. Deuterium and tritium, although they are both isotopes of hydrogen, are two different nuclides.

OUTAGE: The state of any circuit component when it is not available to perform its intended function because of some event associated with that component. An outage may or may not cause an interruption of service to customers, depending on the layout of the system.

PARALLEL POWER: Independent generation which is linked to and synchronized with the bulk electricity system.

PEAK DEMAND: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or, more usually, the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

PEAK PERIOD: Periods during which relatively high demands are placed on an electrical system, as opposed to off-peak periods.

PEAKING UNIT: A generating unit intended to be operated intermittently to supply peak loads.

pH SCALE: is used to measure acidity or alkalinity. Neutral solutions have a pH of 7, acid solutions have a pH less than 7, and alkaline solutions have a pH greater than 7. Each unit change in pH represents a tenfold change in acidity. For example, rainfall with pH 4 is 10 times as acidic as rainfall with pH 5 and 100 times as acidic as rainfall with pH 6.

POLLUTION RIGHTS: A system of marketable permits allowing the bearer to emit a specified level of pollutants. Under this rights system, the government controls the total level of emissions, but not the distribution of these emissions among firms.

POWER POOL: A grouping of two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements.

POWER REACTOR: A nuclear reactor whose primary purpose is to produce energy. Reactors in this class include electric power reactors, heat-producing reactors (producing heat for industrial processing, to supply district heating systems, etc.) and propulsion reactors in nuclear-powered surface vessels and submarines.

POWER SYSTEM: All the interconnected facilities of an electrical utility. A power system includes the generating stations, transformers, switching stations, transmission lines, substations, distribution lines and circuits to the customers' premises; that is, all the facilities required to provide electrical services to the customers.

PRIMARY ENERGY SOURCE: The source of primary energy from which electricity is generated, including falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, biomass, direct solar radiation, geothermal energy and tidal energy.

PRIME MOVER: The turbine or engine that drives an electrical generator.

PUMPED STORAGE: An arrangement in which water is pumped from a lower to a higher reservoir, during off-peak hours. During peak hours, the water is allowed to return to the lower reservoir through hydroelectric turbines, thus generating power. Usually the turbines are reversible so that they can also serve as the pumps in the system.

QUALIFYING FACILITY (QF): Generating unit qualifying for special regulatory treatment under the Public Utility Regulatory Policies Act of 1978.

RADIOACTIVE WASTE: Unwanted radioactive materials obtained in the processing, handling or utilization of radioactive substances. Such wastes may be classified according to their degree of activity or to their half-lives, as follows.

A. According to the radionuclide contents:

high-level waste: the highly radioactive liquid separated during the chemical reprocessing of irradiated fuel; or irradiated reactor fuel if it is not foreseen that the spent fuel will be reprocessed; or any other waste with a comparable radioactivity level.

intermediate-level waste: waste of a lower radioactivity level than high-level waste, but which still requires shielding during handling.

low-level waste: waste which does not require shielding during normal handling because of its low radionuclide content.

B. According to the half-life of the radioactive waste:

long-lived waste: waste that will not decay to an acceptable activity level in a period of time during which administrative controls can be expected to last.

short-lived waste: waste which will decay to a level considered to be insignificant from a radiological viewpoint, in a time period during which administrative controls can be expected to last. In some jurisdictions, radionuclides with a half-life of less than 30 years are considered to fall into this category.

RADIOACTIVE WASTE MANAGEMENT: All activities, administrative and operational, that are involved in the handling, treatment, conditioning, transportation, storage and disposal of radioactive waste.

RADIOACTIVITY: The property of certain nuclides of spontaneously emitting particles or gamma radiation from their nucleus, of undergoing spontaneous fission, or of emitting X-radiation.

RELIABILITY: The ongoing ability of a power system to avoid outages and continue to supply electricity with the appropriate frequency and voltage to customers.

RENEWABLE ENERGY SOURCE: A source of energy which is inherently self-renewing, such as the various manifestations of solar energy (water power, biomass, wind energy, direct solar radiation, wave energy and ocean currents), tidal energy and geothermal energy.

RESERVE MARGIN: The difference between generating capacity and peak load, expressed as a percentage of peak load.

RESERVE (GENERATING) CAPACITY: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required for two main reasons: in case of the unexpected breakdown of generating equipment; and in case the actual peak load is higher than forecast.

RETAIL WHEELING: Wheeling for delivery of power to a retail customer.

RIGHT-OF-WAY: The strip of land on which a power line is located, and on which the power company has acquired the legal right to perform construction and maintenance, to restrict the growth of vegetation, and sometimes to restrict construction by other parties. The width of the right-of-way varies with line voltage.

RUN-OF-THE-RIVER PLANT: A hydroelectric generating station having negligible capacity for the storage of water, so that the plant has to run on the natural flow of the river. The output of the plant may therefore be subject to considerable variation.

SCHEDULED MAINTENANCE: Maintenance of equipment performed in accordance with a prearranged schedule.

SEASONAL DIVERSITY: The diversity between loads that reach their maximum values at different seasons of the year. For example, most Canadian power systems experience their annual peak loads in the winter, whereas many U.S. systems have their annual peaks in the summer because of air conditioning. Systems that differ in this way can effect economies of scale by exchanging energy on a seasonal basis.

SERVICE AREA: The area within which a utility is required, or has the right, to serve consumers.

SHORT-TERM POWER: Power and associated energy which one utility purchases from another for the purpose of obtaining a supply of power intended to be available at all times during the period covered by the commitment.

SOCIAL BENEFITS: Benefits, whether tangible or intangible, resulting from a project. Social benefits are distinguishable from private benefits in that they include all the benefits of a project, whether or not they accrue to project sponsors.

SOCIAL COSTS: Costs or damages, whether tangible or intangible, which a project causes to be imposed. Social costs are distinguishable from private costs in that they include all the costs of a project incurred by all citizens rather than those only incurred by the project sponsors.

SORBENT: An additive used to enhance sulphur dioxide removal, e.g. lime.

SPINNING RESERVE: That portion of the reserve generating capacity which is actually in service, connected to the system, spinning (but not generating full power), and which is ready to pick up load automatically at a moment's notice.

SPLIT SAVINGS: A widely-used formula for the pricing of energy, especially economy energy sold by one utility to another, in which the total saving resulting from a sale is split equally between buyer and seller.

STABILITY: The ability to maintain synchronous operation following disturbance.

STATION SERVICE: The electricity required at a generating station to run the auxiliary plant plus the capacity represented by the losses in the generator transformers.

STORAGE: The water held in a reservoir. Storage is used to even out the natural variations of flow in a river, so that the output of hydroelectric generation can be made as independent as possible of such natural variations.

SUBSTATION: A station at which the voltage of the bulk power system is stepped down to a level suitable for distribution, and at which the feeders at this lower voltage originate and may be switched on or off.

SULPHUR DIOXIDE: A heavy, odourless, suffocating gas with the chemical formula SO_2. Sulphur dioxide is created by both natural and anthropogenic activities. Anthropogenic sources include fossil fuel combustion and industrial activities. High levels of sulfur dioxide and suspended particulate matter (SPM) may cause respiratory problems among adults and children and may also result in lower respiratory tract illness.

SUMMER PEAK: The highest load on a power system during the summer, usually caused by air conditioning in hot weather.

SUPERCONDUCTOR: An electrical conductor offering negligible resistance to the flow of electricity.

SURPLUS ENERGY: Energy that is surplus to the needs of its owner, including both load and reserve. Surplus energy can be produced whenever the total generating capacity exceeds the total load, and is often sold on an interruptible basis.

SUSPENDED PARTICULATE MATTER (SPM): Levels of SPM rise both from human and natural activities including combustion of wood and fossil fuels, industrial activities, and dust raised by vehicular traffic or wind. High SPM levels may aggravate respiratory illnesses.

SWITCHING STATION: A station at which the transmission lines of a power system can be selectively connected or disconnected by means of switchgear.

SYNCHRONISM: The condition of alternating current generators being "in phase;" that is, timed so that their voltage waves reach the maximum and minimum values at exactly the same instant. This is an essential condition in order for alternating current generators to operate on the same system.

SYNCHRONOUS TIE: Any alternating current tie line. All generating units interconnected by the tie must be in synchronism.

TERAWATT HOURS (TW.h): One billion kilowatt-hours.

THERMAL GENERATING STATION: An electric generating station where the prime movers are driven by gases or steam produced by burning fuels (such as coal, oil, gas, wood or refuse) or by nuclear processes.

THERMAL REACTOR: A reactor in which fission is induced predominantly by thermal or "slow" neutrons.

TIME-OF-USE (TIME-DIFFERENTIATED) RATES: Rates which vary based on the time of day, day of the week, or season of the year.

TON: Also known as a short ton, it contains 2,000 pounds. One ton equals 0.9072 tonne.

TONNE: A metric ton, or tonne, contains 1,000 kilograms, or 2,204.623 pounds. One tonne equals 1.1023 tons.

TRANSFORMER: An electromagnetic device for raising or lowering the voltage of alternating current electricity.

TRANSMISSION LINE: A line used for the transmission of electric power at high voltage. Transmission lines may be constructed overhead, underwater or underground. Lines of voltage less than 115 kilovolts are usually considered to be subtransmission or distribution.

TRANSMISSION SYSTEM: Lines, transformers, switches, etc. used to transport electricity in bulk from sources of supply to other principal parts of the system. Transmission is generally at voltages of 115 kilovolts and above.

TURBINE (HYDRAULIC): A rotary type of prime mover in which mechanical energy is produced by the force of water, steam or gas directed against blades fastened to a rotating shaft.

ULTRA HIGH VOLTAGE (UHV): Any voltage in excess of approximately 1000 kilovolts.

VOLTAGE: The electrical force, measured in volts or multiples of volts (e.g. kilovolts) that causes a current to flow in a circuit. In North America, the standard voltage for residential use is 115 volts, with 230 volts used for heavy appliances such as ranges, dryers and hot water heaters. Voltages used for urban and rural distribution range from about 4 kV to 44 kV. The most common transmission voltages are 115, 132, 230, 345, 500 and 735 kV. The higher the voltage, the more power a transmission line can carry.

WATT: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

WET DEPOSITION: A process of precipitation whereby acidic chemicals, including dilute sulphuric and nitric acids and sulphates, are deposited in rain, snow, etc.

WHEELING: The transmission of power belonging to one utility through the circuits of another utility, for delivery either to a third party or back to the originating system.

WINTER PEAK: The highest load on a power system during the 6-month period October to March. In Canada, the winter peak almost always occurs in December or January.

DETAILED BIBLIOGRAPHY

Acid Deposition Research Program. The Present and Potential Effects of Acid and Acidifying Air Pollutants on Alberta's Environment, Summary Report. Calgary, Alberta: Acid Deposition Research Program, September 1988.

Ackerman, Bruce A., and Hassler, William T. Clean Coal/Dirty Air. New Haven, Connecticut: Yale University Press, 1981.

Acton, J. P., and Besen, S. M. The Economics of Bulk Power Exchanges. N-2277-DOE. Washington, D.C.: U.S. Department of Energy, May 1985.

________. Regulation, Efficiency and Competition in the Exchange of Electricity: First-Year Results from the FERC Bulk Power Market Experiment. R-33001-DOE. Santa Monica, California: The Rand Corporation, October 1985.

Alberta. Energy Resources Conservation Board. 240-kV Transmission Line 946/947L, Ellerslie-East Edmonton. Calgary, Alberta: ERCB, May 1989.

________. Energy Resources Conservation Board. Alberta Electric Industry Annual Statistics, 1987. Calgary, Alberta: ERCB, 1988.

________. Energy Resources Conservation Board, and Alberta Public Utilities Board. Small Power Inquiry. ERCB Report 88-A. Calgary, Alberta: ERCB, February 29, 1988.

________. Southern Alberta Institute of Technology, Power Engineering Department. Cogeneration Assessment Study. Prepared for the Alberta/Canada Energy Resources Research Fund. Calgary, Alberta: Southern Alberta Institute of Technology, September 1986.

Alberta Oil Sands Technology and Research Authority. The Greenhouse Effect and the Alberta Fossil Fuels Industry: A Discussion Paper. By Wiggins, E. J. and Yurko, W. J. Edmonton, Alberta: AOSTRA, July 31, 1989.

American Council for An Energy-Efficient Economy. Energy Efficiency: A New Agenda. Washington, D.C.: ACEEE, 1988.

Anderson, Douglas. Regulatory Policies and Electric Utilities. Boston, Massachusetts: Auburn House, 1981.

Anderson, John A., and Pace, Joe D. "Electricity Competition and the Public Interest: A Discussion." Public Utilities Fortnightly. Vol. 121, no. 8, June 23 1988, pp. 37-40.

Armstrong, Christopher and Nelles, H. V. Monopoly's Moment: The Organization and Regulation of Canadian Utilities, 1830-1930. Philadelphia, PA: Temple University Press, 1986.

Arthur Andersen and Co./Cambridge Energy Research Associates. Electric Power Trend. Cambridge, Mass.: Cambridge Energy Research Associates, 1989 edition, p. 8.

Atlantic Council of the United States. U.S. Energy Policy in the 1990s. Draft Policy Paper. Washington, D.C.: August 9, 1989.

Atomic Energy Control Board. CANDU in Canada's Future: A Summary Document. PA-12-1. Mississauga, Ontario: Atomic Energy of Canada Limited, May 1988.

B.C. Hydro and Power Authority. Electric Load Forecast 1987/88 - 2007-08: Low-Probable-High. Vancouver, B.C.: B.C. Hydro and Power Authority, 1987.

_______. The Potential Market for B.C. Exports of Electricity to the U.S.A. Prepared by E.C. Sievwright Associates Limited. Toronto, Ontario: Sievwright Associates Limited, November 1981.

_______. Privatization Act, Bill 45-1988. Vancouver, B.C.: B.C. Hydro and Power Authority, 1988.

_______. Twenty Year Resource Plan for the Period 1988 to 2007. Vancouver, B.C.: B.C. Hydro and Power Authority, March 1988.

B.C. Hydro and TransAlta Utilities. Generation Coordination Study. Calgary: TransAlta Utilities, March 22, 1989.

Bailey, Elizabeth E. "Contestability and Design of Regulatory and Antitrust Policy." American Economic Review. Vol. 71, 1981, pp. 178-83.

_______. Economic Theory of Regulatory Constraint. Lexington, Massachusetts: Lexington Books, 1973.

Barker, Brent. "Deregulation: Facing the Big Issue." EPRI Journal, March 1988, pp. 15-23.

Barrager, Stephen M. "Tools and Techniques for Evaluating Demand-Side Management Options." Presented at Energy Technology Conference XV, Repowering America. Washington, D.C.: Government Institutes Inc., 1988.

Barro, Robert T. "The Control of Politicians: An Economic Model." Public Choice. Vol. 14, Spring 1973, pp. 19-42.

Battle, Ellen F.; Gislason, Gordon S.; and Douglas, Gordon W. Potential Benefits and Costs of Canadian Electricity Exports. Client Research Report 83-1. Calgary, Alberta: Canadian Energy Research Institute, April 1983.

Baumol, William J. Economics, Environmental Policy, and the Quality of Life. Englewood Cliffs, N.J.: Prentice-Hall, 1979.

Baumol, William J., and Klevorick, Alvin K. "Input Choices and Rate-of-Return Regulation: An Overview of the Discussion." Bell Journal of Economics and Management Science. Vol. 1 (1970), pp. 162-190.

Berger, C.; Dubois, R.; Harvie, A.; Lessard, E.; and Loulou, R. "Assessing the Dividends of Power Exchange Between Quebec and New York State: A System Analysis Approach." GERAD. Montreal, Quebec, August 1988.

Berlin, Edward; Cicchetti, Charles J.; and Gillen, William J. "Restructuring the Electric Power Industry.." In W. Shaker and W. Steffy, eds. Electric Power Reform: The Alternatives for Michigan. Ann Arbour, Michigan: University of Michigan, 1976.

Bernard, Jean-Thomas, and Cairns, Robert D. "On Public Utility Pricing and Foregone Economic Benefits." Canadian Journal of Economics. Vol. 20, no. 1, February 1987, pp. 152-63.

_______. Public Electric Utilities: Structure, Policy and Price. Departement d'economique, Universite Laval. Montreal, Quebec: December 1987.

_______. U.S. Electricity Imports from Quebec and the Fair Trade Issue. Montreal, Quebec: Laval University, May 1987.

Berndt, Ernst R. Modelling the Aggregate Demand for Electricity: Simplicity vs. Virtuosity. Cambridge, Massachusetts: The MIT Press, March 1983.

Berrie, T. W. Power System Economics. IEE Power Engineering Series 5. London, U.K.: Peter Peregrinas Ltd., 1983.

Berry, William W. "The Case for Competition in the Electric Utility Industry." Public Utilities Fortnightly. Vol. 110, September 16, 1982, pp.13-20.

Berstien, Marver H. Regulating Business by Independent Commission. Princeton, N.J.: Princeton University Press, 1955.

Best, Melanie S. Formulating Policy for Electric Power: The California Experience. Discussion Paper Series E-85-10. Energy and

Environmental Policy Center, John F. Kennedy School of Government, Harvard University. Cambridge, Massachusetts: John F. Kennedy School of Government, Harvard University, July 1985.

Best, William A. "Electric Power Development in Alberta and British Columbia." A Presentation to the Eleventh Canadian National Energy Forum. Calgary, Alberta, November 22, 1988.

_______. "The Role of Hydroelectric Power in British Columbia." Presented to the Energy Options Conference. Montreal, Quebec, December 1987.

Blackman, B. Glenn Jr. A Futures Market for Electricity: Benefits and Feasibility. Discussion Paper Series E-85-07. Energy and Environmental Policy Center. Cambridge, Massachusetts: John F. Kennedy School of Government, Harvard University, July 1985.

Blair, Peter D. "Technology Issues and Constraints in a Transition to Competitive Bulk Power Markets." Presented at Energy Technology Conference XV, Repowering America. Washington, D.C.: Government Institutes Inc., 1988.

Bodansky, David. Risk Assessment and Nuclear Power. Discussion Paper E-81-11. Energy and Environmental Policy Centre, John F. Kennedy School of Government. Cambridge, Massachusetts: John F. Kennedy School of Government, Harvard University, October 1981.

Bohn, Roger.; Golub, Bennett W.; Tabors, Richard D.; and Schweppe, Fred C. "Deregulating the Electric Utility Industry." MITEL-82-003. Cambridge, Massachusetts: Massachusetts Institute of Technology Energy Laboratory Working Paper, 1982.

Bonneville Power Administration. BPA Issues Alert. Portland, Oregon: Bonneville Power Administration, various issues.

_______. Calculation of Environmental Costs and Benefits Associated with Hydropower Development in the Pacific Northwest. Portland, Oregon: Bonneville Power Administration, April 1986.

_______. Intertie Alternatives: Economic Analysis, Phase I. Submitted by the Resource Work Group to the Interregional Marketing Group Transmission Subcommittee. Portland, Oregon: Bonneville Power Administration, April 1984.

Booth, R. R. "Power System Simulation Model Based on Probability Analysis." IEEE Transactions on Power Apparatus and Systems. Vol. PAS-91, January/February 1972, pp. 62-69.

Bourne, T.W. Power System Economics. London, U.K.: Peter Peregrinas Ltd., 1983.

Boxall, James A., Jr. "The Colossus of the North: The Role of Canadian Power in America's Energy Future." Public Utilities Fortnightly. Vol. 122, no. 3, August 4 1988, pp. 4-5.

Boyd, R. A., and St. Jacques, M. "The Hydro-Quebec City." In The 1971 Proceedings of the Canadian Electrical Association. Montreal, Quebec: CEA, 1972.

Braithwait, Steve. "Electric Utility Strategic Forecasting in a Competitive Environment." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists. Washington, D.C.: IAEE, November 1987.

Brewer, H. L., and Rohnatian, Morteza. "Risk Adjusted Performance Measures for Diversified Public Utility Firms." The Journal of Energy and Development. International Research Center for Energy and Economic Development, University of Colorado, Spring 1987, pp. 185-202.

Breyer, Stephen. Regulation and Its Reform. Cambridge, Massachusetts: Harvard University Press, 1982.

Bridges, G. E., and Scott, A. D. An Evaluation of Potential Ricardian Hydro Electric Rents. Vancouver, B.C.: Department of Economics, University of British Columbia, June 1981.

British Columbia. Ministry of Energy, Mines and Petroleum Resources. British Columbia Energy Supply and Requirements Forecast: 1984-2005. Forecasts and Special Projects Branch, Energy Resources Division. Victoria, B.C.: Ministry of Energy, Mines and Petroleum Resources, August 1986.

Broadman, Harry G., and Hogan, William W. Oil Tariff Policy in An Uncertain Market. E-86-11. Energy and Environmental Policy Center, John F. Kennedy School of Government. Cambridge, Massachusetts: John F. Kennedy School of Government, Harvard University, November 1986.

Calgary Chamber of Commerce. "Environment and the Emerging Political Agenda," revised September 1989. Submission to the Canadian Chamber of Commerce. Calgary, Alberta: Calgary Chamber of Commerce, September 1989.

California. California Energy Commission. 1986 Electricity Report Appendixes. P106-87-001A. Sacramento, California: CEC, December 1986.

________. California Energy Commission. Avoided Cost of Electricity. By Mike Ringer. Sacramento, California: CEC, 1984.

________. California Energy Commission. California Energy Demand, 1985-2005. Volume I (P300-87-002) and Volume II (P300-87-004). Sacramento, California: CEC, 1987.

________. California Energy Commission. California Energy Demand, 1987-2007. Volumes II to XI, consecutively numbered P300-87-005 to P300-87-013. Sacramento, California: CEC, 1987.

________. California Energy Commission. California Energy Outlook: 1987 Biennial Report. Sacramento, California: CEC, 1987.

________. California Energy Commission. Commercial Status of Electrical Generation Technologies. P300-85-003. Sacramento, California: CEC, June 1985.

________. California Energy Commission. Demand Forecasting Issues CFM7. P300-87-015. Prepared for consideration in the 1988 Electricity Report Proceedings. Sacramento, California: CEC, August 1987.

________. California Energy Commission. Documentation of the California Energy Commission's Production Cost Model. P300-82-002. Sacramento, California: CEC, 1982.

________. California Energy Commission. The Economic Impacts of Self Generation. P500-87-002. Sacramento, California: CEC, March 1987.

________. California Energy Commission. Energy Watch. Energy Forecasting and Planning Division. Sacramento, California: CEC, January/February 1988.

________. California Energy Commission. Production Cost Modelling of the PG&E System. P500-85-010. Sacramento, California: CEC, 1985.

________. California Energy Commission. Production Cost Modelling of the Southern California Edison System. P-500-83-011. Sacramento, California: CEC, 1985.

________. California Energy Commission. Relative Cost of Electricity Production. By Mike Ringer. Sacramento, California: CEC, December 1983.

________. California Energy Commission. Relative Cost of Electricity Production. P300-86-006. Sacramento, California: CEC, April 1987.

California Energy Commission/California Public Utilities Commission. Joint CEC/CPUC Hearings on Excess Generating Capacity and Appendices. Report to the Legislature. Sacramento, California: CEC, November 1987.

California Public Utilities Commission. Workplan 1987: A CPUC Access Guide. Sacramento, California: CEC, February 2, 1987.

Canada. Energy, Mines and Resources Canada. Canada-United States Electricity Trade. Ottawa, Ontario: EMR, July 1987.

_______. Energy, Mines and Resources Canada. Canadian Electricity Policy. Ottawa, Ontario: EMR, September 1988.

_______. Energy, Mines and Resources Canada. CANMET Technology Focus. Ottawa, Ontario: CANMET, 1989.

_______. Energy, Mines and Resources Canada. Electric Power Statistics, Vol. 1: Annual Electric Power Survey of Capability and Load. Ottawa, Ontario: Minister of Supply and Services, November 1987.

_______. Energy, Mines and Resources Canada. Electric Power in Canada 1987. Ottawa, Ontario: Minister of Supply and Services, 1988.

_______. Energy, Mines and Resources Canada. Electric Power in Canada 1988. Ottawa, Ontario: Minister of Supply and Services, 1989.

_______. Energy, Mines and Resources Canada. Energy In Canada: An Overview. Ottawa, Ontario: Minister of Supply and Services, January 1987.

_______. Energy, Mines and Resources Canada. Energy Market Analysis Division. Long-Term Energy Outlook 1987-2005. Ottawa, Ontario: EMR, June 1988.

_______. Energy, Mines and Resources Canada. The Canada-U.S. Free Trade Agreement and Energy: An Assessment. Trade: Securing Canada's Future. Ottawa, Ontario: Minister of Supply and Services, 1988.

_______. Energy, Mines and Resources Canada. The Canadian Energy Record 1945-1985. An Overview of Energy Developments and Policy Decisions. 0433A/23A/RT. Ottawa, Ontario: Minister of Supply and Services, 1988.

_______. Energy, Mines and Resources Canada. Uranium in Canada: 1986. Assessment of Supply and Requirements. Ottawa, Ontario: Minister of Supply and Services, 1987.

_______. Energy, Mines and Resources Canada. Coordination and Strategic Planning. "Employment Impact of Energy Management Investment." Presentation to the Select

Committee on Energy. Toronto, Ontario: EMR, October 3, 1988.

________. Energy, Mines and Resources Canada. The Energy Record: 1945-1985. An Overview of Energy Development and Policy Decisions. Ottawa, Ontario: EMR, 1988.

________. Energy, Mines and Resources Canada. UEXGEN MODEL USER's GUIDE. Ottawa, Ontario: The Financial & Market Analysis Branch, Market Analysis Section, December 1985.

________. Energy, Mines and Resources Canada and Ministry of State, (Forestry and Mines). EMR's Commitment to the Environment. Ottawa, Ontario: Minister of Supply and Services, 1988.

________. Energy Mines and Resources and U.S. Department of Energy. Canada/United States Electricity Exchanges, Ottawa, Ontario: Minister of Supply and Services, May 1979.

Canada. Environment Canada. "Acid Rain: The Facts." Ottawa, Ontario: Environment Canada, flyer.

________. Environment Canada. Development of a National Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) Management Plan for Canada. Ottawa, Ontario: Environment Canada, Conservation and Protection Branch, July 1989.

________. Environment Canada. Emissions and Trends of Common Air Contaminants in Canada: 1970 to 1980. Report EPS 7/AP/17. Ottawa, Ontario: Environment Canada, September 1986.

________. Environment Canada. "Stopping Acid Rain: The Canadian Program." Ottawa, Ontario: Environment Canada, flyer.

________. Federal/Provincial Long Range Transport of Air Pollutants Steering Committee. Development of a National Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) Management Plan for Canada. Executive Summary. First Report to Canadian Council of Ministers of the Environment (CCME), Environment Canada, updated July 1989.

________. House of Commons. Minutes of Proceedings and Evidence of the Standing Committee on Energy, Mines and Resources. Pursuant to Standing Order 960-2 Economics of Nuclear Power in Canada. Issue No. 29, November 3, 1987.

________. House of Commons. Nuclear Energy: Unmasking the Mystery. Tenth Report of the Standing Committee on Energy, Mines and Resources. B. Sparrow, Chairman.

Ottawa, Ontario: Standing Committee on Energy, Mines and Resources, August 1988.

________. House of Commons. Report of the Special Committee on Acid Rain. Stan Darling, Chairman. Ottawa, Ontario: Queen's Printer, September 1988.

________. National Energy Board. Canadian Electric Utilities: Analysis of Generation and Trends, 1986. Ottawa, Ontario: Minister of Supply and Services, 1988.

________. National Energy Board. Canadian Energy Supply and Demand, 1987-2005. Ottawa, Ontario: Minister of Supply and Services Canada, September 1988.

________. National Energy Board. Reason for Decision: Hydro Quebec Exports to the New England Utilities. EH-3-87. Ottawa, Ontario: NEB, February 1988.

________. National Energy Board. Reason for Decision: Hydro-Quebec Exports to Vermont Joint Owners. EH-4-87. Ottawa, Ontario: NEB, February 1988.

________. National Energy Board. Report of an Inquiry by a Panel of the National Energy Board. The Regulation of Electricity Exports. Ottawa, Ontario: Minister of Supply and Services, June 1987.

________. National Energy Board. The Regulation of Electricity Exports: Report of an Inquiry By a Panel of the National Energy Board Following a Hearing in November and December 1986. Ottawa, Ontario: Minister of Supply and Services Canada, June 1987.

________. National Research Council. Division of Energy. Alternative Energy Technology in Canada: NRC's R&D Program 1975-1985. Ottawa, Ontario: Department of Supply and Services, September 1986.

________. Statistics Canada. Electric Power Statistics. Catalogue No. 57-202. Vol. II. Ottawa, Ontario: Minister of Supply and Services Canada, various years.

________. Statistics Canada. Historical Statistics of Canada. Series Q85-91. Ottawa, Ontario: Minister of Supply and Services Canada, various years.

________. Statistics Canada. Quarterly Report on Energy Supply-Demand in Canada. Catalogue No. 57-003. Ottawa, Ontario: Minister of Supply and Services Canada, various years.

Canadian Electrical Association., Research and Development, Generation Committee. "Advisory Panel Priorities." Montreal, Quebec: Canadian Electrical Association, draft report.

________. Electricity '87. Montreal, Quebec: Canadian Electrical Association, 1987.

________. Electricity: A Canadian Advantage." Submission to the Energy Options Conference September 1987. Montreal, Quebec, 1987.

________. Energy Efficient Motors in Canada. Prepared by Marbek Resource Consultants Ltd. Montreal, Quebec: Canadian Electrical Association, February 1988.

________. Environmental Planning for Transmission Line Route Selecting In Canada. Prepared by Reid Crowther and Partners Ltd. Montreal, Quebec: Canadian Electrical Association, February 1988.

________. Joint Right of Way Use by Pipelines and Powerlines: Symposium Proceedings. Vancouver, B.C., March 1987.

________. Load Demand Management. Volumes I and II. Prepared by Sangamo Company Limited. Montreal, Quebec: Canadian Electrical Association, December 31, 1978.

________. Reliability Assessment of HVDC Transmission. Montreal, Quebec: Canadian Electrical Association, November 1987.

________. Research and Development Report of Activities 1987. Montreal, Quebec: Canadian Electrical Association, 1987.

________. Status of Load Management. Prepared by Cogeneration Associates Limited. Montreal, Quebec: Canadian Electrical Association, August 1983.

Canadian Electrical Association and Energy, Mines and Resources Canada. Demand Side Management in Canada. Ottawa, Ontario: EMR Canada, May 1989.

Canadian Energy Research Institute. Cogeneration and Parallel Electric Power Generation: The Opportunities, March 30-31, 1987. Calgary, Alberta: CERI, September, 1987.

Canadian International Development Agency. Annual Report, 1986-1987. Ottawa, Ontario: Minister of Supply and Services Canada, 1987.

Canadian National Energy Forum. "Energy Opportunities in the Nineties: An Eastern Canadian Perspective." Proceedings of the 10th Canadian National Energy Forum. St. John's, Newfoundland, October 7-8, 1987.

Canadian Nuclear Association. A Study of Canadians' Attitudes Toward the Use of Nuclear Energy to Generate Electricity in Canada. No. 2541. Prepared by Decima Research. Toronto, Ontario: Canadian Nuclear Association, October 1987.

________. Nuclear Canada, Yearbook 1988. Toronto, Ontario: Canadian Nuclear Association, 1988.

________. Submission to The World Commission on Environment and Development. Toronto, Ontario: Canadian Nuclear Association, March 1986.

Carron, Andrew S., and MacAvoy, Paul W. The Decline of Service in Regulated Industries. Washington, D.C.: American Enterprise Institute, 1981.

Carstensen, E. L. Biological Effects of Transmission Line Fields. New York, N.Y.: Elsevier, 1987.

Casazza, John A. "Free Market Electricity: Potential Impacts of Utility Pooling and Coordination." Public Utilities Fortnightly. Vol. 121, no. 4, February 18, 1988, pp. 16-23.

Chandler, William U.; Geller, Howard S.; and Ledbetter, Marc R. Energy Efficiency: A New Agenda. Washington, D.C.: American Council for an Energy-Efficient Economy, July 1988.

Choudhury, Sushil Kumar. A Regional Model for Planning the Expansion of the Electric Generation and Long Distance Transmission System in Canada (1980-2010): A Linear Programming Approach. Thesis submitted for Master of Applied Science, University of Toronto. Toronto, Ontario. (Undated).

Christensen, Laurits R., and Green, William H. "An Econometric Assessment of Cost Savings from Coordination in U.S. Electric Power Generation." Land Economics. Vol. 54, 1978, pp. 139-155.

Chronicle Herald, March 9, 1989, p. 47.

Coal Association of Canada. Coal and Ontario's Energy: A Practical Partnership. Submission to the Ontario Select Committee on Energy. Toronto, Ontario: Coal Association of Canada, October 1988.

Comtois, Wilfred H. "On the Necessity of Regulation." Public Utilities Fortnightly. Vol. 122, no. 3, August 4, 1988, pp. 13-15.

Corio, Marie R. "Why Is the Performance of Electric Generating Units Declining?" Public Utilities Fortnightly, April 29, 1982, pp. 3-8.

Corio, Marie R, and Lazo, Sandra L. The Adequacy of U.S. Electric Supply Through the Year 2000. Washington, D.C.: Applied Economic Research Co., Inc., March 1987.

Corum, Kenton R., and Morlan, Terry H. "Conservation as a Resource: Implications for Demand Forecasting Methods." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists. Washington, D.C.: November 1987.

Crew, Michael A., ed. Regulatory Reform and Public Utilities. Lexington, Massachusetts: Lexington Books, 1982.

Crowe, T. W. "The Impact of Different Capacity Allocation Methods on Cost Studies." Presentation at the Canadian Electrical Association Conference. Winnipeg, Manitoba, March 1982.

The DPA Group Inc. in association with CH_4 International Ltd., RCG/Hagler, Bailly, Inc. and Steven G. Diener and Associates Ltd. Study on the Reduction of Energy-Related Greenhouse Gas Emissions: Executive Summary, March 1989.

The DPA Group Inc. in association with CH_4 International Ltd., RCG/Hagler, Bailly, Inc. and Steven G. Diener and Associates Ltd. Study on the Reduction of Energy-Related Greenhouse Gas Emissions, March 1989.

Dales, John H. Hydroelectricity and Industrial Development, Quebec 1898-1940. Cambridge, Massachusetts: Harvard University Press, 1957.

Demarco, Dr. Carolyn. "The Shocking News About Computers and Your Health." Today's Health, supplement to the Globe and Mail. Vol. 7, no. 5 (October/November 1989), pp. 57-62.

Demsetz, Harold. "Why Regulate Utilities?" Journal of Law and Economics. Volume 11, April 1968, pp. 55-65.

Dimopoulos, Dionissis. "Pricing Schemes for Regulated Enterprises and Their Welfare Implication in the Case of Electricity." Bell Journal of Economics. Vol. 12, 1981, pp. 185-200.

"Don't Let Finished Nukes Sit Idle." Business Week, August 8, 1988, p. 84.

Dowlatabadi, Hadi, and Harrington, Winston The Effects of Uncertainty on Policy Instruments: the case of electricity supply and environmental regulations. Discussion Paper QU 89-20. Washington, D.C.: Quality of the Environment Division, Resources for the Future, July 1989.

Dowlatabadi, Hadi, and Toman, Michael A. Changes in Electricity Markets and Implications for Generation Technologies

Improving Performance of Wholesale Electric Generation Markets. Discussion Paper ENR 89-01. Washington, D.C.: Energy and Natural Resources Division, Resources for the Future, January 1989.

Dowlatabodi, Hadi, and Tomon, Michael. Resources for the Future. Changes in Electricity Markets and Implications for Generation Technologies. Discussion Paper ENR 87-01. Washington, D.C.: Resources for the Future, January 1989.

Dykema, O. W., and Fraser, W. L. "Development and Commercialization of a Low No_x/So_x Burner." Proceedings of the American Power Conference. Vol. 49. Chicago, Illinois: Illinois Institute of Technology, 1987.

Dyring, Eric. "Sweden After Chernobyl: Revival of the Nuclear Power Debate." Current Sweden, no. 354, March 1987.

Edin, Karl-Axel. "Sweden After Chernobyl: Consequences of the Nuclear Accident." Current Sweden, no. 353, February 1987.

Edison Electric Institute. 1984 Electric Power Annual Report - History and Projections. Washington, D.C.: Edison Electric Institute, 1984.

________. Alternative Models of Electric Power Deregulation. Washington, D.C.: Edison Electric Institute, 1982.

________. Annual Report of Investor Owned Electric Utility Industry: 1986 Financial Review. Washington, D.C.: Edison Electric Institute, 1986.

________. Canada-U.S. Electricity Trade: A Survey of Current Trends, Costs, Benefits and Issues. Prepared by Thomas Connell, School of Urban and Public Affairs, Carnegie-Mellon University. Washington, D.C.: Edison Electric Institute, March 1988.

________. Statistical Yearbook of the Electric Utility Industry. Washington, D.C.: Edison Electric Institute, October 1987.

________. Statistical Yearbook of the Electric Utility Industry. Washington, D.C.: Edison Electric Institute, 1986.

El-Abiad, Ahmed H., ed. Power Systems Analysis and Planning. Washington, D.C.: Hemisphere Publishing Corporation, 1983.

Elder, P. S. Soft is Hard: Barriers and Incentives in Canadian Energy Policy. Calgary, Alberta: Detselig Enterprises Limited, 1984.

Electric Power Research Institute. Bidding for Electric Resources: An Industry Review of Competitive Bid Design and Evaluation. Prepared by Mark J. Matousek and William J. LeBlanc for EPRI. Palo Alto, California: EPRI, November 1988.

———. Capacity Factors and Costs of Electricity for Conventional Coal and Gasification - Combined Cycle Power Plants. Final report by Zaininger Engineering Company, EPRI AP3551, RP2029-11. Palo Alto, California: EPRI, June 1984.

———. Cost Uncertainty in Programming Models of Electricity Supply. EA-1636. Prepared by A. L. Fletcher & Associates. Palo Alto, California: EPRI, November 1980.

———. Demand Side Management, Volume 4: Commercial Markets and Programs. EPRI EA/EM-3597. Prepared by Battelle-Columbus Division, Synergic Resource Corporation and Enviro-Management and Research Inc. Palo Alto, California: EPRI, September 1987.

———. Demand-Side Management Volume 3: Technology Alternatives and Market Implementation Methods. Palo Alto, California: EPRI, December 1984.

———. Demand-Side Management, Volume 2: Evaluation of Alternatives. Prepared by Battelle-Columbus Division and Synergic Resources Corporation for Edison Electric Institute and the Electric Power Research Institute. Palo Alto, California: EPRI, December 1984.

———. Developing Competitive Power Production Strategies for Existing Power Plants. Palo Alto, California: EPRI, February 1987.

———. Electric Utility Rate Design Study. Load Management: Issues, Objectives and Options. The Final Report to the National Association of Regulatory Utility Commissioners. Palo Alto, California: EPRI, February 1982.

———. Impact of Demand Side Management on Future Customer Electricity Demand. EPRI EM-4815-SR. Palo Alto, California: EPRI, October 1986.

———. Inclusion of Cogeneration in Electric Utility Models. EPRI EA-1504, RP1368-01. Final report by Resources Planning Associates Inc. Palo Alto, California: EPRI, September 1980.

———. Incorporating Uncertainty in Energy Supply Models. EPRI EA-0703, RP1012-01. Final report by Futures Group Inc. Palo Alto, California: EPRI, February 1978.

———. Moving Toward Integrated Resource Planning: Understanding the Theory and Practice of Least-Cost Planning and Demand-Side Management. EPRI EM-5065, RP2548-03. Final report by Barakat, Howard and Chamberlain Inc. Palo Alto, California: EPRI, February 1987.

________. Projections on Cost of Development of U.S. Natural Gas Potential. P-5284 Final Report. Prepared by the Institute for Energy Resource Studies. Palo Alto, California: EPRI, January 1988.

________. Small-Hydropower Development: The Process, Pitfalls and Experience. Volume 3: Summary and Analysis of Technology Development Projects. EPRI EM-4-37/Project 1745-15, Final Report. Prepared by Morrison-Knudsen Engineers Inc. Palo Alto, California: EPRI, September, 1987.

________. Technical Limits to Transmission System Operation. EPRI EL-5859. Prepared by Power Technologies, Inc. Palo Alto, California: EPRI, June 1988.

Electric Utility Rate Design. Load Management: Issues, Objectives and Options. Final Report to the National Association of Regulatory Utility Commissions. Palo Alto, California: EPRI, February 1982.

Electricity Planning Technical Advisory Committee. Review of Ontario Hydro's Draft Planning Strategy. Toronto, Ontario: Electricity Planning Technical Advisory Committee, July 1988.

Ellison, William. "European Activities in SO_2 and NO_x Emission Control." Presented at Energy Technology Conference XV, Repowering America. Washington, D.C.: Government Institutes Inc., 1988.

Energy Options Advisory Committee. Energy and Canadians: Into the 21st Century. A Report on the Energy Options Process. Ottawa, Ontario: Minister of Supply and Services Canada, 1988.

Energy Research Group. Energy Research, Directions and Issues for Developing Countries. Prepared for International Development Research Centre, Ottawa and United Nations University, Tokyo, Japan. Ottawa, Ontario: Energy Research Group, 1986.

Environmental Policy Institute. Centralized Power. Washington, D.C.: Environmental Policy Institute, 1979.

________. Project '88, Harnessing Market Forces to Protect Our Environment: Initiatives for the New President. A Public Policy Study sponsored by Senator Timothy E. Wirth and Senator John Heinz. Washington, D.C.: December 1988.

The Evening Telegram, November 28, 1988.

Everest, David. *The Greenhouse Effect: Issues for Policy Makers*. London, England: Joint Energy Programme of the Policy Studies Institute and Royal Institute of International Affairs, 1988

Fairman, James F., and Scott, John C. "Transmission, Power Pools, and Competition in the Electricity Utility Industry." *Hastings Law Journal*. Vol. 28, 1977, pp. 159-207.

Federal/Provincial/Territorial Ministers' Task Force on Energy and the Environment. *Report on Reducing Greenhouse Gas Emissions*. Ottawa, Ontario: Federal/Provincial/Territorial Ministers' Task Force on Energy and the Environment, August 1989.

________. *Report on Reducing Greenhouse Gas Emissions: Technical Appendices*. Ottawa, Ontario: Federal/Provincial/Territorial Ministers' Task Force on Energy and the Environment, October 1989.

Feher, J. Serman. "Competitive Factors and Assessment Methods." *EPRI Journal*, June 1988.

Feldman, Stephen L.; Bernstein, Mark A.; and Noland, Robert B. "The Cost of Completing Unfinished U.S. Nuclear Power Plants." *Energy Policy*, June 1988, pp. 270-279.

Ferrar, Terry A.; Clemente, Frank; and Uhler, Robert G. *Electric Energy Policy Issues*. Ann Arbor, Michigan: Ann Arbor Science, 1979.

Ferrar, Terry, and Hughes, William, eds. *Electric Power Strategy Issues*. Palo Alto, California: QED Research, 1983.

Fitzpatrick, Mary E. *The Process of Regulation: Theory and Evidence*. Submitted as Ph.D dissertation, Department of Economics, Northwestern University, 1986.

Flavin, Christopher. *Slowing Global Warming: A Worldwide Strategy*. Washington, D.C.: The Worldwatch Institute, 1989.

Flavin, Christopher, and Burning, Alan B. *Building on Success: The Age of Energy Efficiency*. Worldwatch Paper 82. Washington, D.C.: Worldwatch Institute, March 1988.

Fox-Penner, Peter. "Allowing for Regulation in Forecasting Load and Financial Performance." *Public Utilities Fortnightly*, January 7, 1988.

Fredette, J. G. "How Ontario's Energy Choices Have Been Affected by the National Energy Board." Presentation to Ontario's Energy Choices Conference. Toronto, Ontario, April 3-4, 1989.

"Free Trade's a Ticket to Profit, TransAlta Plotting a New Course." Calgary Sun, May 13, 1988, p. 54.

Fulkerson, William; Auerbach, Stanley I.; Crane, Alan T.; Kash, Don E.; Perry, Alfred M.; Reister, David B.; and Hagan, Charles W., Jr. Editor. Energy Technology R&D: What Could Make a Difference? A study prepared for the U.S. Department of Energy. Oak Ridge, Tennessee: Oak Ridge National Laboratory, May 1989.

Gas Research Institute. Beating the Competition In Industrial Energy Markets: Summary of the Eighth Annual Seminar for the Gas Research Institute Board of Directors and Advisory Council. San Diego, California: Gas Research Institute, August 10-12, 1987.

Geller, Howard S. "U.S. Experience with Utility Demand Management." Presentation to the Ontario Select Committee on Energy. Washington, D.C.: American Council for an Energy-Efficient Economy, September 20, 1988.

Geller, Howard S; Miller, Eric L.; Ledbetter, Marc R.; and Miller, Peter M. Acid Rain and Electricity Conservation. Washington, D.C: The Energy Conservation Coalition and the American Council for an Energy Efficient Economy, 1987.

Gent, Michael. "Electricity Supply and Demand: An Overview." In Proceedings of the American Power Conference. Vol. 49. Illinois Institute of Technology, 1987.

Gerber, Abraham. "Questions for Regulators in a Competitive Electric Utility Environment." Public Utilities Fortnightly, July 21 1988, pp. 11-15.

Gollop, F., and M. Roberts. "Environment Regulations and Productivity Growth: The Case of Fossil-Fueled Electric Power Generation." Journal of Political Economy. Vol. 91, 1983, pp. 654-674.

Golub, Bennett W., and Hyman, Leonard S. "Financial Problems in the Transition to Deregulation." In J. Plummer, T. Ferrar and W. Hughes, eds. Electric Power Strategy Issues. Arlington, Virginia: Public Utility Reports, 1983, pp. 93-115.

Gordon, Marsha. Government in Business. Montreal, Quebec: C.D. Howe Institute, 1981.

Gort, Micheal, and Wall, Richard A. "Foresight and Public Utility Regulation." Journal of Political Economy, February 1988, pp. 177-88.

________. "Growth in Demand for Public Utility Service: New Rules and Old Principles." Public Utilities Fortnightly. Vol. 121, no. 4, February 18, 1988, pp. 11-15v.

Goudie, Stephen R. How Canadian Electrical Utilities Forecast. Presented at the Canadian Electrical Association Annual Conference. Calgary, Alberta, May 6, 1987.

Government Institute Inc. Energy Technology XV: Repowering America. Proceedings of the Energy Technology Conference, February 17-19, 1988. Washington, D.C.: Government Institute Inc., 1988.

________. Energy Technology XIII. Energy in Transition. Proceedings of the Thirteenth Energy Technology Conference, March 17-19, 1986. Washington, D.C.: Government Institute Inc., 1986.

Great Britain. Parliament. Alternative Energy Sources. (Lords) Select Committee on the European Communities. Session 1987-88. 16th Report. London, England: Her Majesty's Stationery Office, June 21, 1988.

Grisdale, Margaret C. "The Safety Implications of the Legal, Regulatory, and Organizational Framework Within Which Ontario's CANDU Reactors Operate." The Safety of Ontario's Nuclear Power Reactors: A Scientific and Technical Review. Volume 2 Appendices, Appendix VII, Ontario Nuclear Safety Review. Toronto, Ontario, February 29, 1988.

Gustave Speth, James. Our Polluted Environment: A Long-Term Perspective. Washington, D.C.: World Resources Institute, 1988.

Haigh, John A.; Harrison Jr., David; and Nichols, Albert L. Benefits Assessment and Environmental Regulation: Case Studies of Hazardous Air Pollutants. Discussion Paper E-83-06. Energy and Environmental Policy Centre. John F. Kennedy School of Government, Harvard University. Cambridge Massachusetts: John F. Kennedy School of Government, Harvard University, April 1983.

Hamilton, James T., and Lee, Henry, eds. Rapporteur's Report: Executive Session on Northeast Electric Power Policy. Discussion Paper Series E-87-06. Energy and Environmental Policy Center. John F. Kennedy School of Government, Harvard University. Cambridge Massachusetts: John F. Kennedy School of Government, Harvard University, April 1987.

Hamilton, Michael S. "Power Plant Siting and the Environment." Oklahoma Law Review. Vol. 26, 1973, pp. 193-238.

Hare, F. Kenneth. The Safety of Ontario's Nuclear Power Reactors, Volume 1, Report to the Minister, Technical Report and Annexes. Toronto, Ontario: The Queen's Printer for Ontario, February 29, 1988.

Hayes, Mary Shorpe and Scheer, Richard M. "Least-Cost Planning: A National Perspective." Public Utilities Fortnightly, March 19, 1987, pp. 13-18.

Hazell, Stephen, and Jessup, Philip. Greenprint for Canada: A Federal Agenda for the Environment. Ottawa, Ontario: Greenprint for Canada Committee, June 1989.

Hellman, Richard. Government Competition in the Electric Utility Industry: A Theoretical and Empirical Study. New York, N.Y.: Praeger Publishers, 1972.

Hesse, Martha O. (Chairman, FERC). "The Regulatory Challenges Facing the Electric Industry Today." In Proceedings of the American Power Conference. Vol. 49. Illinois Institute of Technology, 1987.

Hilton, George W. "The Basic Behavior of Regulatory Commissions." American Economic Review. Vol. 62, May 1972, pp. 47-54.

Hogan, William W. Energy Demand and The Outlook for Electricity. Discussion Paper Series E-85-09. Energy and Environmental Policy Center. John F. Kennedy School of Government, Harvard University. Cambridge, Massachusetts: John F. Kennedy School of Government, Harvard University, August 1985.

Holliday, Randy E., and Van Toai, Norman. "An Analysis of Cogeneration Development in the United States since PURPA." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists, Washington, November 1987.

Holmes, Andrew. Electricity in Europe. Opening the Market. London, England: Financial Times Business Information Ltd., 1988.

Holte, Kirby C., and Mavis, Steven E. "A Planning Assessment of the Role of Superconductors in the Electric Utility Industry." Presented at Energy Technology Conference XV, Repowering America. Washington, D.C.: Government Institutes Inc., 1988.

Howard, Jeffrey H. and Richard A. Westfall. "FERC Opens Pandoras Box: Increased Competition & Heightened Antitrust Exposure for Electric Utilities." Public Utilities Fortnightly. Vol. 121, no. 5, March 3, 1988, pp. 15-21.

Hufbauer, Gary, and Erb, Joann. *Subsidies in International Trade*. Washington, D.C.: Institute for International Economics, 1984.

Hughes, David. "The Potential Federal Role in Deregulation." In J. Plummer, T. Ferrar, and W. Hughes, eds. *Electric Power Strategy Issues*. Arlington, Virginia: Public Utility Reports, 1983, pp. 119-26.

International Coal Development Institute. *Why Choose Coal? The Case for Coal in Power Generation*. London, England: ICDI, 1988.

International Energy Agency, IEA Coal Research. *CO_2 and Climatic Change*. IEACR/07. London, England: IEA Coal Research, May 1988.

________. *Electricity End-Use Efficiency*. Paris, France: IEA, 1989.

________. *Proceedings of an Experts' Seminar. Energy Technologies for Reducing Emissions of Greenhouse Gases.* Volumes I and II. Paris, France, April 12th-14th, 1989.

Illinois Institute of Technology. *Proceedings of the American Power Conference*. Vol. 49, 1987. Chicago, Illinois: Illinois Institute of Technology, 1987.

"Independents Gearing Up For Battle with Electric Utilities." *Public Utilities Fortnightly*. Vol. 121, no. 4, February 18, 1988, pp. 37-39.

Ingersoll, Richard. "Market Value Transmission." In *Proceedings of the American Power Conference*. Volume 49. Chicago, Illinois: Illinois Institute of Technology, 1987.

Jones, P. M. S., ed. *Nuclear Power: Policy and Prospects*. Toronto, Ontario: John Wiley & Sons, 1987.

Joskow, Paul L. "Contributions to the Theory of Marginal Cost Pricing." *Bell Journal of Economics*. Vol. 7, 1976, pp. 197-206.

________. "Inflation and Environmental Concerns: Structural Change in the Process of Public Utility Price Regulation." *Journal of Law and Economics*. Vol. 17, 1974, pp. 291-328.

________. "Pricing Decisions of Regulated Firms: A Behavioral Approach." *Bell Journal of Economics and Management Science*. Vol. 4, 1973, pp. 118-140.

________. "The Determination of Allowed Rate of Return in a Formal Regulatory Hearing." *Bell Journal of Economics and Management Science*. Vol. 3, 1972, pp. 632-644.

———. *Competition and Deregulation in the Electric Utility Industry*. Cambridge, Massachusetts: MIT Center for Energy Policy Research, May 1987.

———. *Productivity Growth and Technical Change in the Generation of Electricity*. Cambridge, Massachusetts: Massachusetts Institute of Technology Energy Laboratory, December 1985.

———. "Regulatory Failure, Regulatory Reform and Structural Change in the Electrical Power Industry." In *Brookings Papers: Microeconomics 1989*. Washington, D.C.: The Brookings Institute, 1989.

Joskow, Paul L., and MacAvoy, Paul W. "Regulation and the Financial Condition of the Electric Power Companies in the 1970's." *American Economic Review*. Vol. 65, May 1975, pp. 295-301.

Joskow, Paul L, and Schmalensee, Richard. "Incentive Regulation for Electric Utilities." *Yale Journal on Regulation*. Vol. 4:1, 1986.

———. "The Performance of Coal-Burning Electric Generating Units in the United States, 1960-1980." *Journal of Applied Econometrics*. Vol. 2, 1987, pp. 85-109.

———. *Markets for Power: An Analysis of Electric Utility Deregulation*. Cambridge, Massachusetts: The MIT Press, 1983.

Kahn, Alfred E. *The Economics of Regulation: Principles and Institutions*. Vols. 1 and 2. New York, N.Y.: John Willey & Sons, 1970.

Kahn, Edward. *Electric Utility Planning and Regulation*. Washington, D.C.: American Council for an Energy-Efficient Economy, 1988.

Kalt, Joseph P., and Schulke, Frank O., eds. *Drawing the Line on Natural Gas Regulation: The Howard Study on the Future of Natural Gas*. Westport, Connecticut: Quorum Books, 1987.

Kalt, Joseph P.; Lee, Henry; and Hamilton, Jones T. *A Review of the Adequacy of Electric Power Generating Capacity in the United States, 1985-93 and 1993-Beyond*. Discussion Paper E-86-09. Harvard University. Cambridge, Massachusetts: John F. Kennedy School of Government, June 1986.

Kalt, Joseph P.; Lee, Henry; and Leonard, Herman B. *Re-establishing the Regulatory Bargain in the Electric Utility Industry*. Discussion Paper E-8702. Harvard University. Cambridge, Massachusetts: John F. Kennedy School of Government, March 1987.

Kelly, Kevin, ed. National Regulatory Research Institute. Nontechnical Impediments to Power Transfers. Columbus, Ohio: National Regulatory Research Institute, September 1987.

________. National Regulatory Research Institute. Some Economic Principles for Pricing Wheeled Power. Columbus, Ohio: National Regulatory Research Institute, August 1987.

Kemp, William J. The Western Systems Power Pool: A Bulk Power Free Market Experiment. Proceedings of the Eight Annual North American Meeting of the International Association of Energy Economists. November, 1986. Massachusetts Institute of Technology, Cambridge, Massachusetts: IAEE, 1986, pp. 349-354.

Keng, Kenneth C. W. "Forecasting Canadian Nuclear Power Station Construction Costs." Energy Economics, October 1985.

Kent, George F. "Progress Report on the Investigation of Nuclear Plant Costs." Proceedings of the American Power Conference. Vol. 49. Chicago, Illinois: Illinois Institute of Technology, 1987.

Khazzoom, J. D. "Economic Implications of Mandated Efficiency Standards for Household Appliances." Energy Journal. Vol. 1, no. 4, 1980, pp. 21-40.

________. "Energy Saving Resulting from the Adoption of More Efficient Appliances." Energy Journal. Vol. 8, no. 4, 1987, pp. 85-89.

Killian, Linda R., and Trout, Robert R. "Alternatives for Electric Utility Deregulation." Public Utilities Fortnightly, September 16, 1982, pp. 34-39.

King, J.C. "Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest: An Overview." In Analytic Techniques for Energy Planning (ATEP). Elsevier Science Publishers B.V. (North-Holland) 1984, pp. 95-108.

King, Michael J., and Scott, Michael J. "Forecasting Electricity Demand with an End-Use Econometric Model." In Analytic Techniques for Energy Planning (ATEP). Elsevier Science Publishers B.V. (North-Holland) 1984, pp. 151-164.

Komanoff, Charles. Power Plant Cost Escalation: Nuclear and Coal Capital Costs, Regulation and Economics. New York, N.Y.: Van Nastrand Reindhold Company, 1981.

Koodsma, Roger L., and Van Dyke, James W. Technical and Environmental Aspects of Electric Power Generation. Publication No. 2067. Oak Ridge, Tennessee: Oak Ridge National Laboratory, May 1985.

Kosmo, Mark. Money to Burn? The High Cost of Energy Subsidies. Washington, D.C.: World Resources Institute, 1987.

Krishnasomy, Samy G., ed. Probabilistic Methods Applied to Electric Power Systems. Proceedings of the First International Symposium. Toronto, Ontario: Pergamon Press, July 11-13, 1986.

Kruger, Dina Washburn. Investor Responsibility Research Centre. Plugging into Canada: Prospects for U.S.-Canadian Electricity Trade. Washington, D.C.: Investor Responsibility Research Center, 1988.

Kwaczek, Adrienne S., and Kerr, William A. Free Trade and Electricity: Are Canadian Utilities Prepared? Presented at the Canadian Electrical Association Conference. Montreal, Quebec, May 9-12, 1986.

Kwaczek, Adrienne S.; Asgar-Deen, Michael; and Kerr, William A. "Electricity and Issues in Free Trade." Calgary, Alberta, 1988. (Xeroxed.)

Lashof, Daniel A., and Tirpak, Dennis A., eds. Policy Options for Stabilizing Global Climate. Draft report to Congress. Washington, D.C.: United States Environmental Protection Agency, Office of Policy, Planning, and Evaluation, February 1989.

Lee, Byron Jr. "Nuclear Options." In Proceedings of the American Power Conference. Vol. 49. Chicago, Illinois: Illinois Institute of Technology, 1987.

Lee, Henry; Foster, Norman; and Parson, Edward. Canadian Electricity Imports: An Assessment of the National Security, Economic and Environmental Implications. Discussion Paper Series E-88-06. Energy and Environmental Policy Center. John F. Kennedy School of Government, Harvard University. Cambridge, Massachusetts: John F. Kennedy School of Government, Harvard University, April 1988.

Lee, June-Won. The Impact of State Regulatory Practices on Electric Utilities: An Empirical Analysis. Submitted as Ph.D dissertation. Department of Economics. Texas Tech University, 1985.

Lennon, Mark, and Meyers, David. "Net Energy Use Impacts of PURPA Implementation." Public Utilities Fortnightly. Vol. 121, no. 10, May 12, 1988.

Levett, J. L. and Hulkower, S. D. "Bidding and Negotiating for Power from Qualifying Facilities in Massachusetts." In Public Utilities Fortnightly, March 30, 1989.

Linden, Henry R. "The Case of Increasing Use of Natural Gas in Generation." Public Utilities Fortnightly. Vol. 121, no. 4, February 18, 1988, pp. 24-30,

Lindsay, Pfeffer and Associates, Inc.. Emerging Policy Issues in PURPA Implementation. Prepared for the U.S. Department of Energy under contract No. PEACO1-83-PE-70404. Springfield, Virginia: National Technical Information Service, U.S. Department of Commerce, March 1986.

Linke, Simpson, and Schuler, Richard E. "Electric Energy Transmission Technology: The Key to Bulk Power-Supply Policies." Annual Review of Energy. Vol. 13, 1988, pp. 23-45.

Loose, Verne W., and Flaim, Teresa. "Economies of Scale and Reliability: The Economies of Large versus Small Generating Units." Energy Systems and Policy. Vol. 4, 1980, pp. 37-56.

Los Alomos National Laboratory. The Future Market for Electric Generating Capacity: Technical Documentation. Los Alamos, New Mexico: Los Alomos National Laboratory, March 1985.

MacKenzie, James J., and El-Ashry, Mohamed T. Airsick Crops and Trees: The Science and Policy Implications of Multiple Air Pollutants. Washington, D.C.: World Resources Institute, 1988.

MacRae, K. Morgan. A Peak Load Forecasting Model Case Study: The Alberta Interconnected System. Research Report 87-2. Calgary, Alberta: Canadian Energy Research Institute, July 1987.

Manitoba Hydro. A History of Hydro-Electric Power in Manitoba. Winnipeg, Manitoba: Manitoba Hydro, 1984.

Marcus, William B. "Electric Utility Planning for the 1990's." Presentation for the Ontario Select Committee on Energy. Toronto, Ontario: JBS Energy Inc., September 1988.

Mayo, John W. "Multiproduct Monopoly, Regulation, and Firm Costs." Southern Economic Journal. Vol. 51, 1984, pp. 208-218.

McGowan, Francis. "New Developments in Superconducting Materials." Energy Policy, October 1988, pp. 506-513.

_______. "Public Ownership and the Performance of the UK ESI." Energy Policy, June 1988, pp. 221-225.

McMahon, James E. "Enactment of Federal Energy Efficiency Standards for Residential Appliances." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists. Washington, D.C., November 1987.

Meehan, Neil G. Energy: The International Perspective. Some Views on Regulation of Electricity Exports. Energy Options Seminar. Halifax, Nova Scotia, November 1-3, 1987.

Miller, Alan S., and Mintzer, Irving M. World Resources Institute. The Sky is the Limit: Strategies for Protecting the Ozone Layer. Research Report #3. Washington, D.C.: World Resources Institute, 1986.

Miller, John T., Jr. Foreign Trade in Gas and Electricity in North America: A Legal and Historical Study. New York, N.Y.: Praeger, 1970.

Millhone, J. P. "DOE's Least Cost Utility Program." Presented at Energy Technology Conference XIV. Washington, D.C.: Government Institute Inc., 1987.

Mills, Richard L. "Selected Problems in Deregulating the Generation of Electricity." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists. Washington, D.C., November 1987.

Mintzer, Irving. Predicting Climate Change: An Improved Model of Warming Commitment. Washington, D.C.: World Resources Institute, 1988.

________. World Resources Institute. A Matter of Degrees: The Potential for Limiting the Greenhouse Effect. Washington, D.C.: World Resources Institute, 1987.

Mitchell, Bridger M.; Manning, Willard G. Jr.; and Acton, Jan Paul. Peak Load Pricing. Cambridge, Massachusetts: Ballinger Publishing Co., and Rand Corporation, 1978.

Moore, Taylor. "Utility Turbo Power for the 1990s." EPRI Journal, April/May 1988, pp. 5-13.

Moorhouse, John C., ed. Electric Power: Deregulation and the Public Interest. San Francisco, California: Pacific Research Institute For Public Policy, 1986

Munasinghe, Mohan. The Economics of Power Systems Reliability and Planning: Theory and Case Study. Published for the World Bank. Washington, D.C.: John Hopkins University Press, 1979.

Munroe, Tapan. "Electric Utility Competition Lesson from Others." The Journal of Energy and Development. International Research Center for Energy and Economic Development, University of Colorado, Spring 1987, pp. 203-214.

Murphy, Frederick, and Soyster, Allen L. Economic Behavior of Electric Utilities. Englewood Cliffs, N.J.: Prentice-Hall, 1983.

Murray, Peter. "Comparison of U.S. and International Progress in Nuclear Power Generation." Presented at Energy Technology Conference XV, Repowering America. Washington, D.C.: Government Institutes Inc., 1988.

Nagelhout, Mary. "Competitive Bidding in Electric Power Procurement: A Survey of State Action." Public Utilities Fortnightly, March 17, 1988, pp. 41-44.

Naill, Roger F. "Least Cost Alternatives for Electricity Generation." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists. Washington, D.C.: IAEE, November 1987.

National Academy of Science. Acid Deposition: Long Term Trends. Washington, D.C.: National Academy Press, 1986.

National Regulatory Research Institute. Non-Technical Impediments to Power Transfers. Columbus, Ohio: National Regulatory Research Institute, September 1987.

National Task Force on Environment and Economy. Gerard Lecuyer, Chairman. Report of the National Task Force on Environment and Economy. Submitted to the Canadian Council of Resource and Environment Ministers. Downsview, Ontario: Canadian Council of Resource and Environment Ministers, 1987.

Navarro, Peter. "Public Utility Commission Regulation: Performance, Determinants and Energy Policy Impacts." Energy Journal, April 1982, pp. 119-139.

_______. The Dimming of America. Cambridge, Massachusetts: Ballinger Publishing Co., 1985.

_______. The Policy Game. New York, N.Y.: John Wiley & Sons, 1984.

"NB Power Eyes New England Sales after Quebec Deal Fails." The Globe and Mail, January 13, 1989, p. B9.

Nelles, H. V.. The Politics of Development: Forests, Mines and Hydro-Electric Power in Ontario, 1849-1941. Toronto, Ontario: Macmillan, 1974.

Nelson, Karen. Electric Utility Diversification. United States Congressional Research Service. IB82060. Washington, D.C.: Congressional Research Service, September 26, 1983.

Nelson, Randy A. "Regulation, Capital Vintage and Technological Change." Review of Economics and Statistics. Vol. 66, 1984, pp. 59-69.

Netschert, Bruce C. "Energy Implications of the Advances in Superconductivity." Energy Journal. Vol. 9, no. 2, 1988, pp. 45-56.

North American Electric Reliability Council. 1988 Electricity Supply and Demand for 1988-1997: Advance Release. Princeton, New Jersey: North American Electric Reliability Council, May 1988.

_______. 1987 Electricity Supply and Demand for 1987-1996. Princeton, New Jersey: North American Electric Reliability Council, May 1988.

_______. 1987 Reliability Assessment: The Future of Bulk Electric System Reliability in North America 1987-1996. Princeton, New Jersey: North American Electric Reliability Council, 1987.

_______. Reliability Concepts in Bulk Power Electric Systems. Princeton, New Jersey: North American Electric Reliability Council, February 1985.

North American Electric Reliability Journal. 1987 Annual Report. Princeton, New Jersey: North American Electric Reliability Council, 1987.

Northwest Power Planning Council. A Review of Conservation Costs and Benefits: Five Years of Experience Under the Northwest Power Act. Portland, Oregon: Northwest Power Planning Council, October 1, 1987.

_______. Northwest Conservation and Electric Power Plan. Volume 1. Portland, Oregon: Northwest Power Planning Council, 1986.

Oak Ridge National Laboratory. Energy Technology R&D: What Could Make a Difference? Part I: Synthesis Report. Oak Ridge, Tennessee: Oak Ridge National Laboratory, May 1989.

_______. Technical and Economic Aspects of Electric Power Transmission. Oak Ridge, Tennessee: Oak Ridge National Laboratory, May 1985.

_______. Technical and Environmental Aspects of Electric Power Transmission. Environmental Sciences Division Publication No. 2067. Oak Ridge, Tennessee: Oak Ridge National Laboratory, May 1985.

Oates, Wallace E.; Portney, Paul R.; and McGarland, Alberta M. The Net Benefits of Incentive-Based Regulation: The Case of Environmental Standard-Setting in the Real World. Discussion Paper CRM 89-03. Washington, D.C.: Resources for the Future, March 1989.

Ontario. Ontario Energy Board. In the Matter Respecting Ontario Hydro's Proposal to Change its Bulk Power Rates. H.R. 17. Volume I (Report) and II (Appendices). Toronto, Ontario: Ontario Energy Board, 1988.

________. Ontario Energy Board. Report of the Board In the Matter of a Reference Respecting Ontario Hydro. H.R. 16. Volume 1 and Volume 2 - Appendices. Toronto, Ontario: Ontario Energy Board, September 1987.

Ontario. Ontario Ministry of Energy. Cogeneration Potential In Ontario and Limits to its Development. Prepared by Acres International Limited. Toronto, Ontario: Ontario Ministry of Energy, February 1987.

________. Electricity Conservation: Supply Curves for Ontario. Prepared by Marbek Resource Consultants. Toronto, Ontario: Ontario Ministry of Energy, August 1987.

________. Energy 2000: Ontario's Future Electricity Demand. Toronto, Ontario: Ontario Ministry of Energy, July 1987.

________. Report to the Minister of Energy. Review by Government Ministries of Ontario Hydro's Draft Demand/Supply Planning Strategy. Toronto, Ontario: Ontario Ministry of Energy, July 1988.

________. Parallel Generation Policy Paper. Toronto, Ontario: Ministry of Energy, July 20, 1989.

________. Review by Government Ministries of Ontario Hydro's Draft Demand/Supply. Planning Strategy. Report to the Minister of Energy. Toronto, Ontario: Ontario Ministry of Energy, July 1988.

________. Review of Ontario Hydro's Draft Planning Strategy. Report of the Electricity Planning Technical Advisory Panel to the Minister of Energy. Toronto, Ontario: Ontario Ministry of Energy, July 1988.

________. The Economic Impacts of Purchasing Electricity. A study prepared by Data Resources of Canada and Acres International. Toronto, Ontario: Ontario Ministry of Energy, July 20, 1987.

Ontario Hydro. Annual Report 1987. Toronto, Ontario: Ontario Hydro, April 1988.

________. Draft Demand/Supply Planning Strategy. Main Report Report. 666ASP. Toronto, Ontario: Ontario Hydro, December 1987.

———. Draft Demand/Supply Planning Strategy. *Analysis of Representative Plans*. Report BESR 8701. Toronto, Ontario: Ontario Hydro, January 1987.

———. Draft Demand/Supply Planning Strategy. *Analysis of Representative Plans: Social and Community Impacts*. Toronto, Ontario: Ontario Hydro, January 1987.

———. Draft Demand/Supply Planning Strategy. *Analysis of Representative Plans: Environmental Studies and Assessment*. Report No. 86193. Toronto, Ontario: Ontario Hydro, August 1986.

———. Draft Demand/Supply Planning Strategy. *Discussion of Resource Diversity of the Representative Plans*. Report BESR 8706. Toronto, Ontario: Ontario Hydro, January 1987.

———. Draft Demand/Supply Planning Strategy. *Short-term Resource Analysis of the Requirements of Representative Plans, 1986-1991*. Toronto, Ontario: Ontario Hydro, September 1986.

———. Draft Demand/Supply Planning Strategy: Reference Report. *Sensitivity & Risk Analysis of Representative Plans*. Report BESR 8703. Toronto, Ontario: Ontario Hydro, December 1987.

———. Draft Demand/Supply Planning Strategy: Reference Document. *Multi-Criteria Analysis of the Representative Plans*. Report BESR 8705. Toronto, Ontario: Ontario Hydro, January 1987.

———. Draft Demand/Supply Planning Strategy: Reference Document. *Financial Impacts of Representative Plans*. Report BESR 8702. Toronto, Ontario: Ontario Hydro, January 1987.

———. Draft/Supply Planning Strategy: Reference Report, *The Optimal Level of Planning Activity*. Report BESR 8704. Toronto, Ontario: Ontario Hydro, January 1987.

———. *Electrical Efficiency Improvement: Consolidation of Estimates and Update of Planning Target*. Report BESR 87-08. Toronto, Ontario: Ontario Hydro, November 1987.

———. Energy Management Branch. *Ontario Hydro's Plan for Electricity Conservation and Efficiency Measures*. Response to the Honourable Robert Wong, Minister of Energy. Toronto, Ontario: Ontario Hydro, June 1988.

———. *Evaluation Perspectives for Cost-Benefit Analysis for Demand Programs*. Report BESR 87-07. Toronto, Ontario: Ontario Hydro, October 1987.

________. Implementing the Strategy: Ontario Hydro's Strategic Plan for Energy Management, 1988-2000. Toronto, Ontario: Ontario Hydro, June 1988.

________. Load Forecast. No. 871214. Economics and Forecasts Division, Power Systems Program Branch. Toronto, Ontario: Ontario Hydro, May 1988.

________. Options Available to Meet Acid Gas Limits and Selection of Preferred Options. Toronto, Ontario: Ontario Hydro, January 31, 1989.

________. Options for Meeting Acid Gas Limits and Selection of Preferred Options, January 1989.

________. Total Unit Energy Cost Projection: Existing and Committed Fossil and Nuclear Stations. TWEC 87-1, Report BESR 8708, July 1987.

Ontario Nuclear Cost Inquiry Panel. Ontario Nuclear Cost Inquiry: Report to the Minister. Toronto, Ontario: Ontario Nuclear Cost Inquiry Panel, January 1989.

Ontario Nuclear Safety Review. "A Comparison of Nuclear Power Regulation in Canada and the United States." The Safety of Ontario's Nuclear Power Reactors: A Scientific and Technical Review. Selected Consultants' Reports, by John F. Ahearne. Toronto, Ontario, February 29, 1988.

Ontario Select Committee on Energy. Report on Ontario Hydro Draft Demand/Supply Planning Strategy. Volumes I and II, First Session, Thirty-Fourth Parliament. Toronto, Ontario: Legislative Research Service, January 1989.

Organization for Economic Cooperation and Development. Projected Costs of Generating Electricity from Nuclear and Coal-Fired Power Stations for Commissioning in 1995. Paris, France: OECD, April 1986.

Pace, Joe D., and Landon, John H. "Introducing Competition into the Electric Utility Industry: An Economic Appraisal." Energy Law Journal. Vol. 3, no. 1, 1982, pp. 1-65.

Panzar John C., and Willig, Robert D. "Free Entry and the Sustainability of Natural Monopoly." Bell Journal of Economics and Management Science. Vol. 8, 1977, pp. 1-22.

Parker, Alfred L. "Regulating Electric Utilities With a Broader Perspective." Public Utilities Fortnightly, June 25, 1987.

Parker, Larry B. "Economics, Policy and Uncertainty: A Look at Acid Rain Control." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists. Washington, D.C., November 1987.

Parson, Edward A. Midwest-Northeastern Transmission: A Partial Solution to Acid Rain? Discussion Paper E-88-03. Energy and Environmental Policy Centre, John F. Kennedy School of Government, Harvard University. Cambridge, Massachusetts: John F. Kennedy School of Government, Harvard University, June 1988.

Passmore Associates International. Review of Independent Power Bidding Procedures. Prepared for the Ontario Ministry of Energy. Ottawa, Ontario: Passmore Associates International, December 1988.

________. The Private Power Option for Canada. Ottawa: Passmore Associates International, October 1987.

Passmore, J. "Public Policy Issues: Policy Options." In conference proceedings of Cogeneration and Parallel Electric Power Generation: The Opportunities, March 30-31, 1987. Calgary, Alberta: Canadian Energy Research Institute, September 1987.

Pechan, E. H., and Wilson, J. H. Jr. "Estimates of 1973-1982 Annual Sulphur Oxide Emissions from Electric Utilities. Journal of the Air Pollution Control Association. Volume 34, no. 10, October 1984, pp. 1075-1078.

Perlgut, Mark. Electricity Across the Border: The U.S.-Canadian Experience. Washington, D.C: Canadian-American Committee, 1978.

Phillips, Charles F. The Economics of Regulation: Theory and Practice in the Transportation and Public Utility Industries. Homewood, Illinois: Irwin, 1969.

Plourde, Andre. Oil Import Charges and the Canada-U.S. Free-Trade Agreement. Policy Study 88-2. Institute for Policy Analysis. University of Toronto. Toronto, Ontario: Institute for Policy Analysis, March 1988.

Plummer, James L. "A Different Approach to Electricity Deregulation." In J. Plummer, T. Ferrar, and W. Hughes, eds. Electric Power Strategy Issues. Arlington, Virginia: Public Utility Reports, 1983, pp. 45-57.

________. Energy Vulnerability. Cambridge, Massachusetts: Ballinger Publishing Co., 1982.

________. "Tools for Modeling the Stages of Increased Competition In Electricity." Presentation to the International Association of Energy Economists. Houston, Texas, 1988.

Pope, Frederick B. III. "An Overview of Sulphur Dioxide Emission Trends for the United States and Canada." In Proceedings of the American Power Conference. Vol. 49. Chicago, Illinois: Illinois Institute of Technology, 1987.

Portney, Paul R.; Harrison, David, Jr.; Krupruick, Alan J.; and Dowlatabodi, Hadi. "To Live and Breathe in L.A." Reprinted from Issues in Science and Technology. Vol. V, no. 4. Washington, D.C.: National Academy of Sciences, 1989.

Rabinowitz, Mario. "Science and Technology of the New Superconductors." Presented at Energy Technology Conference XV, Repowering America. Washington, D.C.: Government Institutes Inc., 1988.

Ramsey, William. Unpaid costs of Electric Energy: Health and Environmental Impacts from Coal and Nuclear Power. Baltimore, Maryland: Johns Hopkins University Press, for Resources for the Future, 1979.

Reinsch, A. E., and Battle, E. F. Industrial Cogeneration in Canada: Prospects and Perspectives. Study No. 24. Calgary, Alberta: Canadian Energy Research Institute, March 1987.

Reinsch, A. E.; Brown, Kevin J.; and Stanford, James O. Stability within Uncertainty: Evolution of the World Oil Market. Study No. 28. Calgary, Alberta: Canadian Energy Research Institute, September 1988.

Renaud, Donald. "Public Appreciation of Energy Policy Issues." Presentation to the Energy Policy Sector Retreat, May 1988. Communications Branch, Energy, Mines and Resources Canada.

Repetto, Robert. Common Property Resources. Washington, D.C.: World Resources Institute, 1988.

Resources for the Future. Energy and Materials Division. Impact of World Development on Selected Characteristics of the Atmosphere: An Integrative Approach. Volumes I and II. Washington, D.C.: Resources for the Future, 1988.

Ringleb, A. H. "Environmental Regulation of Electric Utilities." Electric Power: Regulation and the Public Interest. J. C. Moorhouse, ed. San Francisco, California: Pacific Research Institute for Public Policy, 1986.

Robertson, J. A. L. Nuclear Energy in Canada: The CANDU System. AECL-6328 (Rev. 1). Ottawa, Ontario: Atomic Energy of Canada Limited, revised July 1984.

Robinson, John B. "Energy Backcasting: a Proposed Method of Policy Analysis." Energy Policy, December 1982, pp. 337-344.

______. "Loaded Questions: New Approaches to Utility Forecasting." Energy Policy. Vol. 16, no. 1, February 1988, pp. 58-68.

Rodford, Bruce W. "FERC Commissions Debate Electric Restructuring." Public Utilities Fortnightly, March 31, 1988, pp. 40-43.

Rogers, J. Scott, and Rowse, John G. Canadian Interregional Electricity Trade: Analyzing the Gains from System Integration During 1990-2020. Discussion Paper 116. Calgary, Alberta: University of Calgary, Department of Economics, March 1989.

Romo, Cheryl. "Four Days in March: When NARUC Took on the FERC." Public Utilities Fortnightly, March 31, 1988, pp. 25-28.

______. "Transmission Access: The Hot Potato." Public Utilities Fortnightly, July 7, 1988, pp. 30-32.

Rosenberg, Norman J.; Crosson, Pierre; Easterling, William E.; Frederick, Kenneth; and Sedjo, Roger. Policy Options for Adaptation to Climate Change. Discussion Paper ENR 89-05. Washington, D.C.: Climate Resources Program, Resources for the Future, March 1989.

Rothman, Mitchell P. "Free Trade and Electricity." Presented to ICEED Conference. Boulder, Colorado, April 8, 1988.

Rowse, John. Economic Benefits of Co-operative Power Supply Expansion. Queen's University and The University of Calgary. Calgary, Alberta: University of Calgary, December 1979.

Royal Commission on Electric Power Planning. Nuclear Power in Ontario, Issue Paper #1. Toronto, Ontario: Royal Commission on Electric Power Planning, September 1986.

Rozek, Richard P. "Competitive Bidding in Electricity Markets: A Survey." The Energy Journal. Vol. 10, no. 4. Weston, Massachusetts: Oelgeschlager, Gunn and Hain, Publishers, Inc., October 1989.

Ruff, Larry E. "Least-Cost Planning and Demand-Side Management: Six Common Fallacies and One Simple Truth." Public Utilites Fortnightly, April 28, 1988, pp. 19-26.

Ruff, Louis E. The Basic Economics of Utility Least-Cost Planning and Demand-Side Management. Washington, D.C.: Putnam, Hayes and Bartlett, Inc., October 1987.

Runnalls, O. Planning Energy Supplies for People. Presented at the 27th Annual Conference Canadian Nuclear Association. St. John, New Brunswick, June 15, 1987.

Rusche, Ben C. "Nuclear Waste Management." In Proceedings of the American Power Conference. Volume 49, 1987. Illinois Institute of Technology. Chicago, Illinois, 1987.

Saskatchewan Power Corporation. Electrical Energy Requirements: 1988-2008. Regina, Saskatchewan: Saskatchewan Power Corporation, June 1988.

Schafer, John C. "Status of Photovoltaics For Commercial Power Generation." Presented at Energy Technology Conference XV, Repowering America. Washington, D.C.: Government Institutes Inc, 1988.

Scherer, C. R. "Estimating Peak and Off-Peak Marginal Costs for an Electrical Power System: An Ex-Ante Approach." Bell Journal of Economics and Management Science. Vol. 7, no. 2, 1976, pp. 575-601.

Schmalensee, Richard. "A Note on Economies of Scale and Natural Monopoly in the Distribution of Public Utility Services." Bell Journal of Economics. Vol. 9, 1978, pp. 270-76.

________. The Control of Natural Monopoly. Lexington, Massachusetts: Lexington Books, 1979.

Scientific American. "Managing Plant Earth." Special Issue. Vol. 261, no. 3, September 1987.

Seagraves, James A. "Regulating Utilities with Efficiency Incentives." Public Utilities Fortnightly, January 5, 1984, pp. 18-23.

Segal, Mark D. "Canada's Electric Power Export Potential." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists. Washington, D.C., November 1987.

Seiden, Kenneth P. Hydroelectric Public Utilities and Wholesale Markets for Power. Submitted as Ph.D dissertation, Department of Economics, University of Oregon, 1986.

Select Committee on Energy. Report on Ontario Hydro Draft Demand/Supply Planning Strategy. Volumes I and II, First Session, Thirty-Fourth Parliament. Toronto, Ontario: Legislative Research Service, January 1989.

Shaker, William H., ed. Electric Power Reform: The Alternatives for Michigan. Ann Arbor, Michigan: The University of Michigan, 1976.

Shepard, Micheal. "The Politics of Climate." EPRI Journal, June 1988, pp. 4-15.

Sherif, F. "Dynamic Properties of the EMR Energy Demand and Price Modelling System." Proceedings of the Eighth Annual International Association of Energy Economists North American Conference. Cambridge, Massachusetts, May 1987.

Sichel, Werner, and Gies, Thomas G. Applications of Economic Principles in Public Utility Industries. Ann Arbor, Michigan: University of Michigan, 1981.

Sillen, John O., and Siegel, John R. "With High Electric Demand Growth, Whither Least-Cost Planning?" Public Utilities Fortnightly. Volume 122, no. 2, July 21, 1988, pp. 16-22.

Silverman, Lester P. "Restructuring the Electric Utility Industry." In Energy Economics and Energy Politics. Proceedings of the Ninth Annual North American Meeting of the International Association of Energy Economists. Washington, D.C., November 1987.

Skea, Jim. "UK Policy on Acid Rain." Energy Policy, June 1988, pp. 252-269.

Smith, Irene M. CO_2 and Climatic Change. IEACR/07. London, England: International Energy Agency and IEA Coal Research, May 1988.

Smith, Philip. Brinco: The Story of Churchill Falls. Toronto, Ontario: McClelland and Stewart, 1975.

Smock, Robert and Mona Reynolds. "New Utility Generating Plants: When, Where, and By Whom." In Power Engineering, April 1989.

Southam Energy Group. Energy in Canada 1987. Toronto, Ontario: Southam Communications Ltd., 1987.

Southern Alberta Institute of Technology. Power Engineering Department. Cogeneration Assessment Study. Prepared for the Alberta/Canada Energy Resources Research Fund. Calgary, Alberta: SAIT, September 1986.

Sponseller, Diane. "The Return to Conservation Principles." Public Utilities Fortnightly. Vol. 121, no. 4, February 18, 1988, pp. 50-54.

Stahl, Len. A Record of Service: The History of Western Canada's Pioneer Gas and Electric Utilities. Edmonton, Alberta: Canadian Utilities Ltd., 1987.

Stigler, George J. "The Theory of Economic Regulation." Bell Journal of Economics and Management Science. Vol. 2, Spring 1971, pp. 3-21.

Surrey, John. "Nuclear Power: An Option for the Third World." Energy Policy, October 1988, pp. 461-479.

Suzuki, David. It's a Matter of Survival. CBC Ratio. Transcripts of a five-part series on CBC Radio. Toronto, Ontario, October 1989.

T. Ingledow and Associates Limited. Federal-Provincial Working Committee on Long Distance Transmission National Power Network- Stage II Assessment. Vancouver, B.C.: T. Ingledow and Associates Limited, February 28, 1967.

Talukdar, Sarosh, and Gellings, Clark, W., eds. Load Management. New York, N.Y.: IEEE Press, 1987.

Templeton, David S. and Read, Wallace S. "The Newfoundland Story." In The 1975 Proceedings of the Canadian Electrical Association. Montreal, Quebec: CEA, 1976.

Terzic, Branko, and McKinnon, James. "Gas in Britain: Regulation of a Privatized Former State Monopoly." Public Utilities Fortnightly. Vol. 121, no. 11, May 26, 1988, pp. 20-27.

Toman, Michael A. and Darmstadter, Joel. Improving Performance of Wholesale Electric Generation Markets. Discussion Paper ENR 88-03. Washington, D.C.: Energy and Natural Resources Division, Resources for the Future, December 1988.

Torrens, Ian M. "Global Greenhouse Warming: Role of the Power Generation Sector and Mitigation Strategies." Prepared for the IEA/OECD Expert Seminar on Energy Technologies for Reducing Emissions of Greenhouse Gases, Paris, France April 12-14, 1989. Palo Alto, CA: Electric Power Research Institute, 1989.

Trabandt, Charles A. "Ending Up Someplace Else." Atomic Industrial Forum Monthly Meeting, July 21, 1987.

United States. Department of Energy. Energy Information Administration. Analysis of Nuclear Power Plant Operating Costs. DOE/IEA 0511. Washington, D.C.: U.S. Department of Energy, 1988.

_______. Department of Energy. Energy Information Administration. Annual Energy Outlook 1987 With Projections to 2000. Washington, D.C.: U.S. Department of Energy, March 28, 1988.

_______. Department of Energy. Energy Information Administration. Annual Outlook for U.S. Electric Power 1987: Projections Through 2000. DOE/EIA-0474(87). Washington, D.C.: U.S. Department of Energy, May 1987.

———. Department of Energy. Energy Information Administration. Annual Report to Congress 1987. Washington, D.C.: U.S. Department of Energy, February 1988.

———. Department of Energy. Energy Information Administration. Commercial Nuclear Power 1987: Prospects for the United States and the World. DOE/EIA-0438(87). Washington, D.C.: U.S. Department of Energy, July 1987b.

———. Department of Energy. Energy Information Administration. Domestic Uranium Mining and Milling Industry: 1986 Viability Assessment. DOE/EIA-0477(86). Washington, D.C.: U.S. Department of Energy, November 1987.

———. Department of Energy. Energy Information Administration. Electric Power Quarterly. July/September 1987.

———. Department of Energy. Energy Information Administration. Electric Power Annual 1986. DOE/EIA 0348(86). Washington, D.C.: U.S. Department of Energy, September 1987.

———. Department of Energy. Energy Information Administration. A Guide for the Assessment of Technologies for Generating Electricity. DOE/EIA - 0344. Washington, D.C.: U.S. Department of Energy, June 1982.

———. Department of Energy. Energy Information Administration. Nuclear Plant Cancellations: Causes, Costs, and Consequences. Washington, D.C.: U.S. Department of Energy, April 1983.

———. Department of Energy. Energy Information Administration. Nuclear Power Plant Construction Activity 1987. DOE/EIA 0473(87). Washington, D.C.: U.S. Department of Energy, June 1988.

———. Department of Energy. Energy Information Administration. PC-AEO Forecasting Model and Documentation for the Annual Energy Outlook, 1987. Washington, D.C.: U.S. Department of Energy, April 1988.

———. Department of Energy. Energy Information Administration. Revenue Requirements Modelling System (RRMS) Documentation. Volume I - Methodology Description and User's Guide (DOE/PE/70403-H1/1) and Volume 2 (DOE/PE/7403-H1/2), March 1986.

———. Department of Energy. Energy Information Administration. Regional Projections of End Use Energy Consumption and Prices Through 2000. Prepared as internal report. Washington, D.C.: U.S. Department of Energy, April 1987.

———. Department of Energy. Energy Information Administration. U.S. - International Electricity Trade: Projections through

1995. DOE/EIA-0496. Washington, D.C.: U.S. Department of Energy, September 1986.

________. Department of Energy. Energy Information Administration. World Nuclear Fuel Cycle Requirements 1986. Washington, D.C.: U.S. Department of Energy, September 1986.

________. Department of Energy. Office of Coal and Electricity Policy. Emerging Policy Issues in PURPA Implementation. An Examination of Policy Issues Related to Federal and State Efforts to Encourage Development of Cogeneration and Small Power Production Under Title II of PURPA. Washington, D.C.: U.S. Department of Energy, March 1986.

________. Department of Energy. Office of Fossil Energy. The Role of Re-Powering in America's Power Generation Future. Washington, D.C.: U.S. Department of Energy, December 1987.

________. Department of Energy. Office of Policy, Planning and Analysis. Electric Supplies for the 1990s: Growing Reliance on Demand Management and Third-Party Suppliers. Washington, D.C.: U.S. Department of Energy, October 1988.

________. Department of Energy. Office of Policy, Planning and Analysis. The Future of Electric Power in America. Washington, D.C.: In-house publication, June 1983.

________. Department of Energy. "Electricity's Future in the United States." A chapter from Energy Security: A Report to the President of the United States, March 1987.

________. Department of Energy. America's Clean Coal Commitment. DOE/FE-0083. Washington, D.C.: U.S. Department of Energy, February 1987.

________. Department of Energy. Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector. Progress Report One: Context and Analytical Framework. Washington, D.C.: U.S. Department of Energy, January 1988.

________. Department of Energy. Electric Power Supply and Demand for the Contiguous United States 1987-1996. Staff report. Washington, D.C.: U.S. Department of Energy, February 1988.

________. Department of Energy. Northern Lights: The Economic and Practical Potential of Imported Power from Canada. By Jeffery Skeer. Washington, D.C.: U.S. Department of Energy, December 1987.

______. Department of Energy. Office of Fossil Energy. "Benefits of Clean Coal Technology." The 8th International Conference on Coal Research. Tokyo, Japan, October 16-20, 1988.

______. Department of Energy. Technical and Environmental Aspects of Electric Power Transmission. ORNL-6165. Prepared by R. L. Krodsma and J. W. VanDyke. Washington, D.C.: U.S. Department of Energy, May 1985.

______. Department of Energy. United States Energy Policy, 1980-1988. Washington, D.C.: U.S. Department of Energy, October 1988.

______. Federal Energy Regulatory Commission. Office of Electric Power Regulation. Power Pooling in the United States. FERC-0049. Washington, D.C.: FERC, December 1981.

______. Federal Energy Regulatory Commission. Administrative Determinants of Full Avoided Costs for Sales of Power to Qualifying Facilities and Interconnecting Facilities. Docket No. RM88-6. Washington, D.C.: FERC, March 16, 1988.

______. Federal Energy Regulatory Commission. . "Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978." Federal Register. Vol. 45, no. 38, February 1980.

______. Federal Energy Regulatory Commission. A Guide to Public Information at FERC. Washington, D.C.: FERC, December 1987.

______. Federal Energy Regulatory Commission. Office of Electric Power Regulation. Power Pooling. FERC--0049. In the United States. Washington, D.C.: FERC, 1981.

______. Federal Energy Regulatory Commission. Regulation Governing Independent Power Producers. Docket No. RM88-4. Washington, D.C.: FERC, March 16, 1988.

______. Federal Energy Regulatory Commission. Regulation Governing Competitive Bidding Programs. Docket No. RM88-5. Washington, D.C.: FERC, March 16, 1988.

______. General Accounting Office. Canadian Power Imports: A Growing Source of U.S. Supply. Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce House of Representatives. Washington, D.C.: United States General Accounting Office, April 1986.

______. Office of Technology Assessment. Commercializing High-Temperature Superconductivity. Washington, D.C.: U.S. Government Printing Office, June 1988.

________. Office of Technology Assessment. Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition. OTA-E-409. Washington, D.C.: U.S. Government Printing Office, May 1989.

________. Office of Technology Assessment. Starpower: The U.S. and the International Quest for Fusion Energy. Washington, D.C.: U.S. Government Printing Office, October 1987.

________. Office of Technology Assessment. Acid Rain and Transported Air Pollutants: Implications for Public Policy. Washington, D.C.: Government Printing Office, 1984.

________. Office of Technology Assessment. New Electric Power Technologies. OTA-E-246. Washington, D.C.: U.S. Government Printing Office, July 1985.

United States. U.S. Congress. Office of Technology Assessment. Biological Effects of Power Frequency and Magnetic Fields - Background Paper. OTA-BP-E-53. Washington, D.C.: U.S. Government Printing Office, May 1989.

Utility Data Institute. Profile of Cogeneration and Small Power Generation Markets, Second Edition. Prepared by Hagler, Bailly & Co. Washington, D.C.: Utility Data Institute, April 1988.

________. The Adequacy of U.S. Electricity Supply Through the Year 2000. UD1-021-87. Prepared by Applied Economic Research Co. Inc. Washington, D.C.: Utility Data Institute, March 1987.

Vancouver Province, July 20, 1989, p. 6.

Vining, Aidan R. "Provincial Hydro Utilities." In Allan Tupper and G. Bruce Doern, eds. Public Corporations and Public Policy in Canada. Montreal, Quebec: Institute for Research on Public Policy, 1981.

Waddel, Thomas G. The Economic Damages of Air Pollution. Washington, D.C.: Government Printing Office, 1974.

Wallace, Megan A. "Efficient Wheeling Rates for the U.S." The Energy Center Quarterly. Vol. 1, no. 2, Spring 1988. University of Pennsylvania Energy Center.

Walter, Michael A., ed. Privatization Tactics and Techniques. Proceedings of a Symposium held July 22-24, 1987. Vancouver, B.C.: The Fraser Institute, 1987.

Weiss, Leonard W. Case Studies in American Industry. Third edition. New York, N.Y.: John Wiley & Sons, 1980.

Wellinghoff, Jon B., and Mitchell, Cynthia K. "A Model for Statewide Integrated Utility Resource Planning." Public Utilities Fortnightly, August 8, 1985, pp. 19-26.

Wenders, John T. "Peak Load Pricing in the Electricity Industry." Bell Journal of Economics. Vol. 7, 1976, pp. 232-241.

Western Systems Coordinating Council. Coordinated Bulk Power Supply Program 1985-1995. San Francisco, California: Western Systems Coordinating Council, April 1, 1986.

Wharton Econometric Forecasting Associates. Power Wheeling In North America. Volumes I and II. Bala Cynwyd, Pennsylvania: Wharton Econometric Forecasting Associates, 1987 and 1988.

Whittaker, M. Curtis. "Conservation and Unregulated Utility Profits: Redefining the Conservation Market." Public Utilities Fortnightly, July 7, 1988.

Wiggins, E. J., and Yurko, W. J. The Greenhouse Effect and the Alberta Fossil Fuels Industry: A Dicussion Paper. Edmonton, Alberta: Alberta Oil Sands Technology and Research Authority, July 31, 1989.

Wilkinson, Max. Power Monopolies and the Challenge of the Market: American Theory and British Practice. Discussion Paper E-89-12. Cambridge, Massachusetts: Energy and Environmental Policy Center, Harvard University, September 1989.

Williams, Bob. "Greenhouse, Acid Raid Worries Bouy Prospects for U.S. Gas, Clean Coal." Oil & Gas Journal, August 29, 1988, pp. 12-17.

Wilson, Richard; Colame, Steven D.; Spengler, John D.; and Wilson, David Gordon. Health Effects of Fossil Fuel Burning, Assessment and Mitigation. Cambridge, Massachusetts: Ballinger Publishing Co., 1980.

Winter, John V., and Conner, David A. Power Plant Siting. New York, N.Y.: Van Nostrand, 1978.

Wong, Robert C. (Ontario Minister of Energy). "Energy Choices for Ontario." Statement to the Select Committee on Energy Room 228, Legislative Building Queen's Park, August 2, 1988.

Woo, Chi-Keung. "Inefficiency of Avoided Cost Pricing of Cogenerated Power." The Energy Journal. Vol. 9, no. 1, 1988.

World Commission on Environment and Development. Energy 2000: A Global Strategy For Sustainable Development. Report to the World Commission on Environment and Development by the Advisory Panel on Energy. London and New Jersey: Zed Books Ltd., 1987.

________. Our Common Future. Oxford, England: University Press, 1987.

World Energy Conference. Environmental Effects Arising From Electricity Supply and Utilization and the Resulting Costs to the Utility. London, England: World Energy Conference, 1988.

World Resources Institute. The Sky Is The Limit: Strategies for Protecting the Ozone Layer. By Alan Miller and Irving Mintzer. Washington, D.C.: World Resources Institute, 1986.

________. World Resources 1988-1989. Report by the World Resources Institute and the International Institute for Energy and Development. Washington, D.C.: World Resources Institute, 1988.

Worldwatch Institute. State of the World 1988. W. W. Norton and Company. Washington, D.C.: Worldwatch Institute, 1988.

Wyatt, Alan. Electric Power Challenges and Choices. Toronto, Ontario: The Book Press Ltd., 1986.

Yates, Marshall. "Superconductivity: An Update on Prospects." Public Utilities Fortnightly, April 28, 1988, pp. 36-39.

Yokell, Michael D., and Violette, Daniel M. "Market Structure and Opportunities in the Electric Utility Industry Today." Public Utilities Fortnightly, January 7, 1988.

Zany, Joseph, P. "Barriers to the Development of Parallel Generation in Canada." In conference proceedings, Cogeneration and Parallel Electric Power Generation: The Opportunities, March 30-31, 1987. Calgary, Alberta: Canadian Energy Research Institute, September 1987.

Zimmer, Michael J.; Orlando, Joseph A.; and Kessler, Michael L., eds. Cogeneration: Current Prospects & Future Opportunities. Rockville, Maryland: Government Institutes, Inc., October 1987.

CANADIAN ENERGY RESEARCH INSTITUTE

SELECTED PUBLICATIONS

December 1989

CANADIAN ENERGY RESEARCH INSTITUTE
SELECTED PUBLICATIONS SINCE JANUARY 1, 1984
COMPLETE PUBLICATION LIST AVAILABLE UPON REQUEST

Studies

No. 33 Critical Issues in Electric Power Planning in the 1990s. Volume I. K. Morgan MacRae. November 1989 (Price $250.00, 303 pages) ISBN 0-920522-59-9.

Critical Issues in Electric Power Planning in the 1990s. Volume II. K. Morgan MacRae. December 1989 (Price $125.00, 343 pages, coil bound).

Critical Issues in Electric Power Planning in the 1990s. Executive Summary. K. Morgan MacRae. November 1989 (Price $50.00, 36 pages) ISBN 0-920522-62-9.

No. 32 Continental Natural Gas Market: Canadian Export Capacity in the 90s. Leonard A. Coad & David H. Maerz. October 1989 (Price $250.00, 155 pages) ISBN 0-920522-60-2.

No. 31 Canadian Crude Oil Supply/Demand Balances. James N. Tanner and Anthony E. Reinsch. August 1989 (Price $75.00, 320 pages) ISBN 0-920522-54-8.

No. 30 Industrial Natural Gas Demand. Merete Heggelund. May 1989 (Price $75.00, 280 pages) ISBN 0-920522-55-6.

Industrial Natural Gas Demand. Executive Summary. Merete Heggelund. May 1989 (Price $55.00, 36 pages) ISBN 0-920522-58-0.

No. 29 Towards a Commercial Future: Ethanol and Methanol as Alternative Transportation Fuels. Michelle Heath. January 1989 (Price $45.00, 329 pages) ISBN 0-920522-53-X.

Towards a Commercial Future: Ethanol and Methanol as Alternative Transportation Fuels. Executive Summary. Michelle Heath. January 1989 (Price $10.00, 35 pages) ISBN 0-920522-56-4.

No. 28 Stability Within Uncertainty: Evolution of the World Oil Market. Anthony E. Reinsch, Kevin J. Brown, and James O. Stanford. September 1988 (Price $55.00, 280 pages) ISBN 0-920522-50-5.

Stability Within Uncertainty: Evolution of the World Oil Market. Executive Summary. Anthony E. Reinsch, Kevin J. Brown, and James O. Stanford. September 1988 (Price $10.00, 30 pages) ISBN 0-920522-52-1.

No. 27 An Assessment of the Potential for Coal-Derived Syncrudes in Canada. K. Morgan MacRae. June 1988 (Price $30.00, 251 pages) ISBN 0-920522-49-1.

No. 26 Towards a Continental Natural Gas Market: Historical Perspectives and Long-Term Outlook. Kevin J. Brown. March 1988 (Price $45.00, 457 pages) ISBN 0-920522-47-5.

No. 25 An Evaluation of Crude Oil Supply in Saskatchewan. James Tanner. December 1987 (Price $30.00, 156 pages) ISBN 0-920522-44-0.

No. 24 Industrial Cogeneration in Canada: Prospects and Perspectives. Anthony E. Reinsch and Ellen F. Battle. March 1987 (Price $30.00, 137 pages) ISBN 0-920522-41-6.

No. 23 Energy Efficiency in Canada's Pulp & Paper Industry. Ellen F. Battle. October 1986 (Price $35.00, 131 pages) ISBN 0-920522-38-6.

No. 22 Natural Gas for Vehicles in Canada: A Study of Market Penetration Problems. Brian D. Sumner. April 1985 (Price $20.00, 99 pages) ISBN 0-920522-37-8

No. 21 Canadian and U.S. Heavy Crude Oil Markets: A Review and Prospects. Volume I. Canadian Energy Research Institute. April 1985 (Price $25.00, 175 pages) ISBN 0-920522-36-X.

Appendix Volume to Study No. 21. Canadian and U.S. Heavy Crude Oil Markets: A Review and Prospects. Volume II. Canadian Energy Research Institute. April 1985 (Price $10.00, 133 pages).

No. 20 The Oil and Gas Investment Climate: Changes Over a Decade. DataMetrics Limited. June 1984 (Price $15.00, 76 pages) ISBN 0-920522-31-9.

Appendix Volume to Study No. 20. The Oil and Gas Investment Climate: Changes Over a Decade. DataMetrics Limited. June 1984 (Price $12.00, 141 pages).

Research Reports

89-1 Oil and Gas Finding Costs in Alberta: 1970-1987. Michele McLachlan. May 1989 (Price $30.00, 53 pages) ISBN 0-920522-57-2.

88-1 Oil and Gas Finding Costs in Alberta: 1970-1986. Janice L. Pasay. May 1988 (Price $10.00, 54 pages) ISBN 0-920522-48-3.

87-2 A Peak Load Forecasting Model Case Study: The Alberta Interconnected System. K. Morgan MacRae. July 1987 (Price $20.00, 81 pages) ISBN 0-920522-42-4.

87-1 Oil and Gas Finding Costs in Alberta: 1970 - 1985. Janice L. Pasay. January 1987 (Price $20.00, 87 pages) ISBN 0-920522-40-8.

86-2 Reserves of Hydrocarbons in Alberta: A Review of Canadian Petroleum Association and Alberta Energy Resources Conservation Board Estimates and Methodology. James N. Tanner. November 1986 (Price $25.00, 130 pages) ISBN 0-920522-39-4.

86-1 The Effect of the Western Accord and Recent Provincial Royalty Changes on Petroleum Industry Capital Expenditures. Janice L. Pasay. March 1986 (Price $15.00, 27 pages).

85-2 Estimated Petroleum Finding Costs in Alberta, 1970-1983. Z. Charles Slagorsky and Janice L. Pasay. October 1985 (Price $15.00, 62 pages).

85-1 The Wolf Lake Project: An Example of Benefits to the Canadian Economy from Commercial Oil Sands Development. Louise Czaja, Michael Kirkegaard, Walter Haessel, and Gordon Douglas. March 1985 (Price $10.00, 67 pages).

84-1 The Costs of Transportation Fuel from Methanol Versus Oil Sands. Brian D. Sumner, Tricia Gibson, and Z. Charles Slagorsky. December 1984 (Price $20.00, 100 pages) ISBN 0-920522-34-3.

Working Papers

85-2 A Partial Regional Comparison of Taxes and Subsidies on Natural Gas, Electricity, and Oil Products in Canada. L. Coad and K. Desbarats. May 1985 (Price $10.00, 78 pages).

85-1 The Implications of Canadian Natural Gas Deregulation. Douglas J. Haughey and Robert T. Liddle. January 1985 (Price $10.00, 97 pages).

84-3 The CERI Energy Pricing and Demand Models: A Description and Internal Evaluation. L. A. Coad. October 1984 (Price $10.00, 45 pages).

84-2 An Assessment of Benefits and Costs of Using Methanol as a Motor Gasoline Extender in Southern Ontario. Walter Haessel and Tricia Gibson. September 1984 (Price $10.00, 62 pages).

84-1 A Review of Oil and Gas Drilling Activity Forecasting Techniques. G. E. Angevine, S. R. Cain, and Z. C. Slagorsky. March 1984 (Price $5.00, 20 pages).

Presentations by Staff (available upon request)

89-10 Outlook for the Canadian Crude Oil Market. Anthony E. Reinsch. Presentation to the Petroleum Joint Ventures Association, Calgary, Alberta, November 1, 1989.

89-9 World Energy Conference Technical Section 3.3: A Review of Papers. Anthony E. Reinsch. Presentation to the World Energy Conference, Montreal, Quebec, September 19, 1989.

89-8 Canada's Experience with Oil Megaprojects. G. E. Angevine. Presentation at the 8th International Symposium on Petroleum Economics, Quebec City, Quebec, September 14, 1989.

89-7 Interpreting the World Oil Market: Fundamentals and Forecasting. Anthony E. Reinsch. Presentation to the Alberta Summer Institute for Petroleum Industry Development, Calgary, Alberta, July 4, 1989.

89-6 Evolution of World Oil Prices. Anthony E. Reinsch. Presentation to the Exploration Update '89 Conference, Calgary, Alberta, June 14, 1989.

89-5 Canadian Natural Gas Export Pipeline Capacity Requirements: An Emerging Issue for the 1990s. Anthony E. Reinsch. Presentation to the Petroleum Society of CIM, 40th Annual Technical Meeting, Banff, Alberta, May 28-31, 1989.

89-4 Oil and Gas Finding Costs in Alberta: Survival in an Uncertain Environment. Anthony E. Reinsch. Presentation to Petroleum Society of CIM, Calgary, Alberta, May 17, 1989.

89-3 Industrial Natural Gas Demand. Merete Heggelund. Presentation to the Canadian Gas Association, Economics/Statistics Committee, Edmonton, Alberta, May 8, 1989.

89-2 Critical Issues in Bioenergy Development: Prices and Prospects Through 2010. Anthony E. Reinsch. Presentation to The Seventh Canadian Bio-energy Research and Development Seminar, Ottawa, Ontario, March 24-26, 1989.

89-1 Towards a Commercial Future: Ethanol and Methanol as Alternative Transportation Fuels. Michelle Heath. Presentation to Alternative Fuels Forum Participants, Regina, Saskatchewan, March 22, 1989.

88-9 Stability Within Uncertainty: Evolution of the World Oil Market. A. E. Reinsch. Presentation to the Canadian Society of Petroleum Geologists, Calgary, Alberta, December 1988.

88-8 Stability Within Uncertainty: Evolution of the World Oil Market. A. E. Reinsch. Presentation to the 10th Annual Meeting, International Association for Energy Economics, Houston, Texas, November 1988.

88-7 The Canadian Natural Gas Resource Base: Reserves, Deliverability and Potential. Kevin J. Brown. Presentation to the CERI/Institute of Gas Technology Canada/U.S. Gas Trade Conference, Chicago, Illinois, November 14-16, 1988.

88-6 Perspectives on Canadian/American Trade in Energy. Dr. G. E. Angevine. Presentation to the Canadian Association of Petroleum Production Accounting Conference, Calgary, Alberta, October 1988.

88-5 Renewable Energy: Offspring of OPEC? A. E. Reinsch. Presentation to the Wood Energy Symposium, Fredericton, New Brunswick, October 1988.

88-4 Energy Options: A Critical Review. A. E. Reinsch. Presentation to the Seventh CERI International Oil and Gas Markets Conference, Calgary, Alberta, September 1988.

88-3 Perspectives on Canada/United States Trade in Energy Commodities. G. E. Angevine. Remarks at a Meeting of the Energy Minerals Division of the American Association of Petroleum Geologists, Bismarck, North Dakota, August 22, 1988.

88-2 Towards a Continental Natural Gas Market: Some Strategic Implications. Kevin J. Brown. Presentation to the U.S. Gas Market in Transition Conference, Calgary, Alberta, June 22-23, 1988.

88-1 Issues in Canada-U.S. Hydrocarbon Trade. Anthony E. Reinsch. Presentation to the Trinational Energy Policy Workshop, Stanford University, Stanford, California, March 21-22, 1988.

87-6 Canadian Natural Gas Supply and its Inter-Relationship with the North American Natural Gas Market. Kevin Brown. Presentation to the Ninth Annual North American Meeting International Association of Energy Economists, Washington D.C., November 1987. Published in the Proceedings, November 1987.

87-5 Notes for Discussion of Aspects of Energy Security in Canada. Morgan MacRae and Merete Heggelund. Presented to Energy Options Seminar, "Energy: The International Perspective," Halifax, Nova Scotia, November 3, 1987.

87-4 A Survey of Energy in Canada. Anthony E. Reinsch. Presentation to the World Energy Congress, Institute for Electrical and Electronic Engineering, Sao Paulo, Brazil, August 19-20, 1987.

87-3 The Economics of Conventional Oil Supply in Saskatchewan. James N. Tanner. Paper presented to the Annual Meeting of the International Association of the Energy Economists, Calgary, Alberta, July 1987. Published in the Proceedings.

87-2 World Oil Market Developments: Implications for the Canadian Crude Oil Supply-Demand Balance. Anthony E. Reinsch. Presentation to the AOSTRA conference, Advances in Petroleum Recovery and Upgrading Technology, Edmonton, Alberta, June 2-3, 1987.

87-1 Industrial Cogeneration in Canada: Prospects and Perspectives. Anthony E. Reinsch. Presentation to the conference on Cogeneration and Parallel Electric Power Generation: The Opportunities, co-sponsored by the Canadian Energy Research Institute and the Ontario Ministry of Energy, Toronto, Ontario, March 30-31, 1987. Published in the Conference Proceedings, September, 1987. ISBN 0-920522-43-2.

85-1 International Drilling 1950-1983: Changes to Reserves and Production of Petroleum and Natural Gas. Shane S. Streifel. Presentation to the Political Economy of World Petroleum: Challenge and Response, 1985-1995, Washington, D.C., April 1-3, 1985.

84-3 Implications of Changing Energy Prices for Canadian Agricultural Producers. J. A. MacMillan. Presentation to the Canadian Agricultural Outlook Conference, Ottawa, Ontario, December 11, 1984.

84-2 A Social Benefit-Cost Analysis of Using Methanol as a Motor Gasoline Extender in Southern Ontario. Walter Haessel and Tricia Gibson. Presentation to the VIth International Symposium on Alcohol Fuels Technology, Ottawa, Ontario, May 21-25, 1984.

84-1 Exportable Natural Gas Surplus: Sensitivity to Oil Prices and Economic Growth. Douglas J. Haughey and Leonard A. Coad. Presentation at the Workshop on Natural Gas Trade in North America, Stanford University, Stanford, California, February 24-25, 1984.

Proceedings

International Oil and Gas Markets Conference. October 1989. Photocopies of available papers ($100/set; $10/individual paper).

Ontario's Energy Choices Conference. April 1989, Toronto, Ontario. Photocopies of available papers ($100/set; $10/individual paper).

International Oil and Gas Markets Conference. September 1988. Photocopies of available papers ($100/set; $25/individual paper).

International Oil and Gas Markets Conference. September 1987. Photocopies of available papers ($100/set; $25/individual paper).

Cogeneration and Parallel Electric Power Generation: The Opportunities. Proceedings of a Conference held March 30, 1987, Toronto, Ontario ($75.00/set; $20/individual paper, 469 pages) ISBN 0-92522-43-7.

International Oil and Gas Markets Conference. September 1986. Photocopies of available papers ($100/set; $25/individual paper).

International Oil and Gas Markets Conference. September 1985. Photocopies of available papers ($100/set; $25/individual paper).

Petroleum and Natural Gas Markets Conference. September 1984. Photocopies of available papers ($100/set; $25/individual paper).

Annual Reports

CERI Corporate Profile, 1988.

Board of Directors' Report for the Year Ended March 31, 1989.